

Technical Study for Community Choice Energy Program in Contra Costa County

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March, 2017

Table of Contents

Executive Summary	i
Loads and Forecast	ii
CCE Power Supplies	iii
Local Renewable Development.....	iv
CCE Rate Analysis Results	iv
Scenarios 1 and 3 (Simple Renewable Compliance)	iv
Scenarios 2 and 4 (Accelerated RPS)	v
Macroeconomic and Job Impacts	vii
Comparative Analysis of CCE Options	viii
Conclusions	x
Chapter 1: Introduction	1
What is a CCE?	1
Assessing CCE Feasibility	2
Chapter 2: Economic Study Methodology and Key Inputs	4
Contra Costa County Loads and CCE Load Forecasts	6
CCE Supplies	9
Power Supply Cost Assumptions	12
Local Solar Analysis	15
Local Solar Modeled in the CCE Scenarios	21
Greenhouse Gas Costs	21
Other CCE Supply Costs.....	21
PG&E Rate and Exit Fee Forecasts	22
PG&E Bundled Generation Rates	22
PG&E Exit Fee Forecast	23
Pro Forma Elements and CCE Costs of Service	24
Pro Forma Elements	24
Startup Costs	25
Administrative and General Cost Inputs	26
Cost of Service Analysis and Reserve Fund	26
Chapter 3: Cost and Benefit Analysis	28
Scenario 1 (Minimum RPS Compliance)	28
CCE Average Costs.....	28
Residential Bill Impacts	29
Greenhouse Gas Emissions	30
Scenario 2 (Accelerated RPS)	31
CCE Average Costs.....	31
Residential Bill Impacts	32
GHG Emissions	33
Scenario 3 (Minimum RPS Compliance plus Local Procurement)	34
CCE Costs	34
Residential Bill Impacts	35
GHG Emissions	35
Scenario 4 (Accelerated RPS plus Local Procurement)	36

CCE Average Costs	36
Residential Bill Impacts	37
GHG Emissions	38
Chapter 4: Sensitivity of Results to Key Inputs.....	39
Lower Participation Sensitivity	39
Higher Local Renewable Power Prices Sensitivity	40
Higher Renewable Power Prices Sensitivity.....	40
Higher Exit Fee (PCIA) Sensitivity	41
Lower PG&E Portfolio Cost Sensitivity	41
Higher Natural Gas Prices Sensitivity	42
Stress Case and Sensitivity Comparisons	42
Conclusions	45
Chapter 5: Macroeconomic Impacts.....	46
How a CCE interacts with the Surrounding Economy	46
Job Impacts of Proposed CCE Scenarios	47
Overview of Scenario Effects	47
Resulting Impacts on Jobs	50
Allocation of Earned Income Gains	55
Chapter 6: Other Risks	58
Financial Risks to CCE Members.....	58
Procurement-Related Risks	59
Legislative and Regulatory Risks	60
PCIA Uncertainty.....	60
Impact of High CCE Penetration on the PCIA	61
Impact of High CCE Penetration on Low-Carbon (Hydro) Resources	61
Bonding Risk.....	62
Chapter 7: Comparative Analysis of CCE Options.....	63
Rates	64
GHG Reduction	65
Local Economic Benefits	65
CCE Governance: Voting.....	66
CCE Governance: Other	69
Timing and Process to Join/Form.....	70
Costs to Join the CCE	71
Exiting the CCE.....	71
Remaining With PG&E.....	72
Summary	73
Chapter 8: Other Issues Investigated.....	75
Synergies on the Northern Waterfront	75
“Minimum” CCE Size?	76
Individuals and Communities Self-Selecting 100% Renewables.....	77
Competition with a PG&E Solar Choice Program	78
Differences Between the Analyses for Contra Costa and Alameda Counties	79
Chapter 9: Conclusions	82

List of Acronyms

AAEE	Additional Achievable Energy Efficiency
CAISO	California Independent System Operator
CBA	Collective Bargaining Agreement
CCA	Community Choice Aggregation
CCE	Community Choice Energy
CEC	California Energy Commission
CPUC	California Public Utilities Commission
EE	Energy Efficiency
EBCE	East Bay Community Energy
ESPs	Energy Service Providers
FY	Fiscal Year
GHG	Greenhouse Gas
GRP	Gross Regional Product
GWh	Gigawatt-hour (= 1,000 MWhs)
IOU	Investor-Owned Utility
I/T	Information Technology
JEDI	Jobs and Economic Impact (model)
JPA	Joint Powers Authority
kWh	Kilowatt-hour
MW	Megawatt
MWh	Megawatt-hour
NREL	National Renewable Energy Laboratory
PCIA	Power Charge Indifference Adjustment
PEIR	Programmatic Environmental Impact Report
PG&E	Pacific Gas & Electric
REC	Renewable Energy Credit
REMI	Regional Economic Modeling Inc
RPS	Renewable Portfolio Standard
SB 350	Senate Bill 350
TURN	The Utility Reform Network

Executive Summary

Main Findings

1. This study finds that the jurisdictions in Contra Costa County studied¹ in this report have several options for implementing a Community Choice Energy (CCE) program that would likely result in lower greenhouse gas (GHG) emissions, increased local renewable energy generation, and increased local job creation compared to remaining with current electricity service from the Pacific Gas and Electric Company (PG&E).
2. The electricity rates charged under various CCE scenarios available to the jurisdictions covered in this study would likely be similar or less than the rates charged by PG&E for comparable service. The degree to which CCE rates are reduced below comparable PG&E rates depends in large part on the extent to which the CCE pursues policy objectives other than rate minimization in its energy procurement practices. Competing policy objectives may include increasing the supply of locally generated renewable energy, promoting energy efficiency, and maximizing local employment generated from a CCE program.
3. This study finds that Contra Costa County includes enough technically feasible locations to meet a significant proportion of electricity demand for the area studied through locally generated renewable energy. Forty percent of the technically feasible sites fall within the Northern Waterfront Economic Development Initiative area.
4. The implementation of a CCE program within the studied area is projected to create between 500 and 700 new jobs within Contra Costa County compared to remaining with current PG&E service, depending on the CCE option implemented.
5. This study compares three CCE program alternatives to current PG&E service and identifies the tradeoffs associated with these four alternatives. The decision of which program alternative to implement will require policy makers to balance costs and potential risks and benefits of each option, which are described in detail.

Purpose of this Study

Community Choice Energy is described in State law as “Community Choice Aggregation.” California Assembly Bill 117, passed in 2002, established Community Choice Aggregation in California to provide the opportunity for local governments or special jurisdictions to procure or provide electric power for their residents and businesses. On March 15, 2016, the Contra Costa County (County) Board of Supervisors directed County staff to work with cities within the County to obtain electrical load data from PG&E for conducting a technical study of options for

¹ The communities constituting the “Contra Costa CCE” throughout the report are Antioch, Brentwood, Clayton, Concord, Danville, Hercules, Martinez, Moraga, Oakley, Orinda, Pinole, Pittsburg, Pleasant Hill, San Ramon, and unincorporated County. They do not include those communities already being served by the Community Choice Aggregator, MCE (El Cerrito, Lafayette, Richmond, San Pablo, and Walnut Creek).

implementing CCE within the County’s unincorporated area and the 14 cities within the County not currently participating in a CCE program. The Board of Supervisors further directed the CCE technical study to compare alternatives for implementing CCE (i.e., establishing a Contra Costa County-Only CCE or joining one of the neighboring CCEs – MCE, formerly Marin Clean Energy, or East Bay Community Energy) to the option of remaining with PG&E.

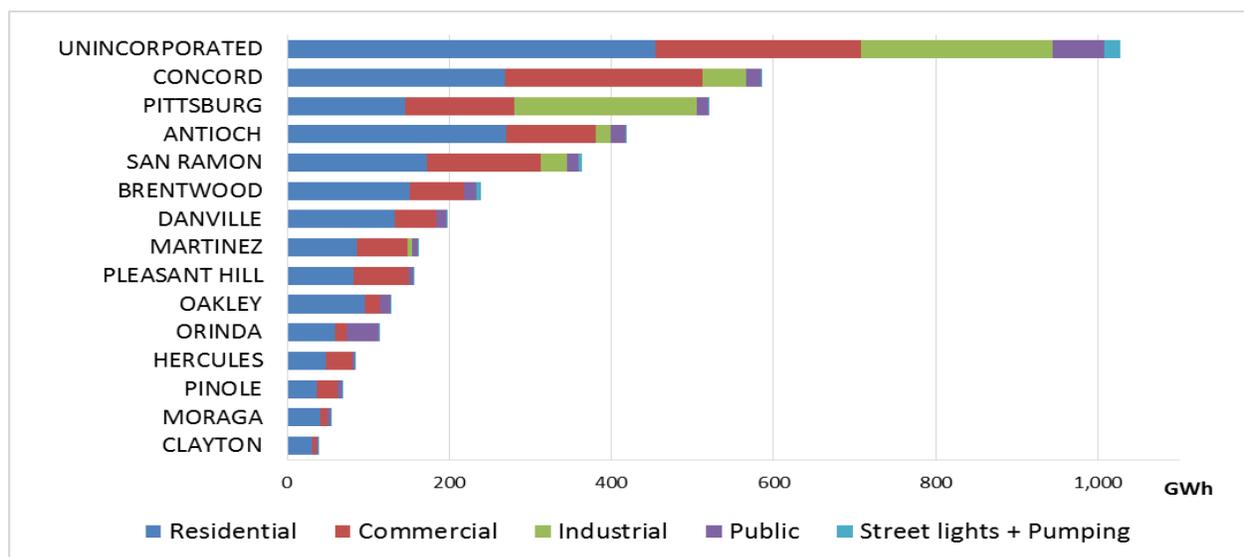
To assess whether a stand-alone CCE is “feasible” in Contra Costa County, the local objectives must be laid out and understood. Based on the specifications of the initial request for proposals and input from the County, this study:

- Quantifies the electric loads that a Contra Costa County CCE would serve;
- Includes analysis of in-county renewable generation;
- Compares the rates that could be offered by the CCE to PG&E’s rates;
- Calculates the macroeconomic development and employment benefits of CCE formation; and
- Compares the benefits and risks of forming a CCE or joining a neighboring CCE versus remaining on PG&E bundled service.

Loads and Forecast

Figure ES-1 provides a snapshot of Contra Costa County bundled electric load in 2015 by city and by rate class.² As the figure shows, total bundled electricity load in 2014 from Contra Costa County was approximately 4,000 GWh. The unincorporated areas of the County represented 25% of County load, and the cities of Concord and Pittsburg were together responsible for another 25%. Residential and commercial customers made up most the County load, with smaller contributions from the industrial and public sectors.

² “Bundled” load includes only load for which PG&E supplies the power; it excludes load from Direct Access customers, load in the jurisdiction of another CCE provider, and load met by customer self-generation. This excludes load originating in the cities of El Cerrito, Lafayette, Richmond, San Pablo, and Walnut Creek, which are served by MCE.

Figure ES-1. PG&E's 2015 Bundled Load in Contra Costa County

CCE Power Supplies

The CCE's primary function is to procure supplies to meet the electrical loads of its customers. By law, the CCE must also supply a certain portion of its sales to customers from eligible renewable resources. This Renewable Portfolio Standard (RPS) requires 33% renewable energy supply by 2020, increasing to 50% by 2030. The CCE may additionally choose to source a greater share of its supply from renewable sources than the minimum requirements, or may seek to otherwise reduce the environmental impact of its supply portfolio. The CCE may also use its procurement function to meet other objectives, such as sourcing a portion of its supply from local projects to promote economic development in the County. The four supply scenarios considered in this analysis are summarized in Table ES-1.

Table ES-1: Four Scenarios Modeled³

Scenario:	1	2	3	4
% RPS-Eligible in 2020	33%	50%	33%	50%
% RPS-Eligible in 2030	50%	80%	50%	80%
Share of RPS-Eligible from Local Resources	0%	0%	50%	50%

³ Customer-sited solar is not considered RPS-eligible in California and is not included in the RPS procurement in these scenarios. Customer-sited solar is incorporated in this analysis as a reduction to the CCE's load.

Local Renewable Development

The CCE may choose to contract with or develop renewable projects within Contra Costa County to promote economic development or reap other benefits. This study found 1,395 parcels that met the established criteria and 1,875 individual sites within the identified parcels where either a solar shade structure, large rooftop, or ground mounted system could be developed. Table ES-2 shows the total solar PV generation capacity within the County based on the methodology and assumptions in Chapter 3.

Table ES-2. Total PV Solar Generation Potential and Build Cost

	Ground Mount	Shade Structure	Roof Mounted	Total
PV Capacity (MW)	1,891	1,320	144	3,355
PV Production (GWh)	3,025	2,113	230	5,369
Build Cost (\$ Millions)	\$3,417	\$3,977	\$371	\$7,660
Build Cost (\$/Watt)	\$1.99	\$3.10	\$2.62	\$2.56
No of PV Systems	845	886	144	1,875

CCE Rate Analysis Results

Scenarios 1 and 3 (Simple Renewable Compliance)

In Scenario 1, the CCE meets the mandated 33% RPS requirement in 2020 and the 50% RPS requirement in 2030, plus the 55% proposed target between 2030 and 2038. Annual GHG emissions are 50% lower on average than PG&E's forecasted annual GHG emissions by assuming a fraction of the non-RPS power is provided by large hydroelectric resources.

Figure ES-2 summarizes the results of Scenario 1. The figure shows the total average cost of the Contra Costa County CCE to serve its customers (vertical bars) and the comparable PG&E generation rate (line).⁴ Of the CCE cost elements, the greatest cost is for non-renewable generation (including large hydroelectric), followed by the cost for renewable generation, which increases over the years per the RPS requirements. Another important CCE customer cost is the Power Charge Indifference Adjustment (PCIA), which is the mandated charge that State regulators require PG&E to impose on all CCE customers.⁵

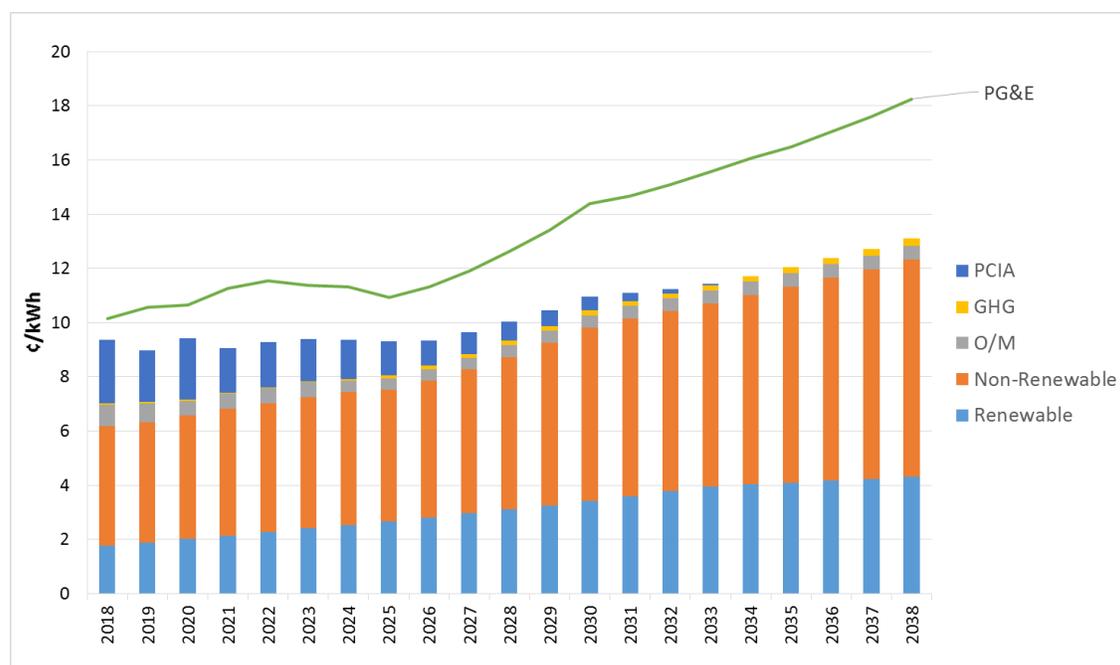
⁴ All rates are in nominal dollars. Note that these are NOT the full rates shown on PG&E bills. They are only the generation portion of the rates. Other parts of the rate, such as transmission and distribution, are not included, as customers pay the same charges for these components regardless of who is providing their power.

⁵ Per current regulations, the PCIA fee is expected to decrease in most years beginning in 2019 and to have less of an impact on CCE customer rates over time as resources expire from PCIA eligibility for CCE customers. However, given that PCIA regulations are subject to change, the possibility that PCIA rates may not decrease as expected is considered in the High PCIA scenario.

Under Scenario 1, the differential between PG&E generation rates and the average cost for the Contra Costa County CCE to serve its customers (*aka* the CCE rates) is positive in each year (i.e., CCE rates are lower than PG&E rates). As a result, Contra Costa County CCE customers' average generation rate (including contributions to the CCE's reserve fund) can be set at a level that is lower than PG&E's average customer generation rate in each year.

Scenario 3 is the same as Scenario 1 except that by 2028 one-half of the renewable power is provided by local resources. The differential between PG&E generation rates and Contra Costa County CCE customer rates in Scenario 3 is lower than in Scenario 1; the expected Contra Costa County CCE rates continue to be lower than the forecast PG&E generation rates for all years from 2018 to 2038.

Figure ES-2. Scenario 1 Forecast Average CCE Cost and PG&E Rates, 2018-2038



Scenarios 2 and 4 (Accelerated RPS)

Under Scenario 2, the Contra Costa County CCE starts with 50% of its load being served by renewable sources in 2017, and increases this at a quick pace to 80% renewable energy content by 2030. Scenario 4 is the same as Scenario 2 except that by 2027 one-half of the renewable power is provided by local resources.

The differential between PG&E generation rates and Contra Costa County CCE customer rates in Scenarios 2⁶ and 4 is narrower than in Scenarios 1 and 3. Still, the expected Contra Costa County CCE rates continue to be lower on average than the forecast PG&E generation rates for all years from 2018 to 2038. However, for Scenario 4—very high local renewable penetration—

⁶ After 2033, the Contra Costa County CCE rates are lower for Scenario 2 than Scenario 1.

the modeling suggests that the CCE might not be able to beat PG&E rates in the 2025-2030 timeframe. (See Chapter 3 for details).

Greenhouse Gas Emissions

Under Scenarios 1 and 3, we include enough GHG-free hydroelectric power so that the Contra Costa County CCE's GHG emissions rate is about half of PG&E's GHG emissions rate. This requires using large hydroelectric power for 35% of the CCE's generation portfolio, on average, from 2018 to 2038. Though this large hydroelectric power would not qualify for RPS requirements, it is considered a non-GHG emitting resource.⁷ Under Scenarios 2 and 4 these additions of large hydro power are not needed once the high renewable targets are met. The result is a portfolio that averages 20% large hydro from 2018 to 2038.

Tables ES-4 shows GHG emissions from 2018-2038 for the Contra Costa County CCE in each Scenario and what PG&E's emissions would be for the same load if no CCE were formed. Overall, the CCE is projected to reduce GHG emissions from the County by about half. This result is due in large part to not only the assumed renewable generation, but also the hydroelectric power assumed to be part of the CCE's supply mix.

Note that the analysis assumes "normal" hydroelectric output for PG&E. During the drought years, PG&E's hydro output has been at about 50% of normal, and the utility has made up these lost megawatt-hours through additional gas generation. This means that the "normal" PG&E emissions shown here are lower than the "current" emissions. If, as is expected by many experts, the recent drought conditions are closer to the "new normal", then PG&E's GHG emissions in the first 8 years would be approximately 30% higher. Depending on whether the CCE were similarly affected by limited hydroelectric supply, the CCE's emissions may increase as well.

Table ES-4. Comparative GHG total emissions for PG&E and Contra Costa CCE

GHG emissions	PG&E (KTonnes) ⁸	Contra Costa CCE (KTonnes)	Savings (%)
Scenario 1	5,882	2,957	50%
Scenario 2	5,882	2,693	54%
Scenario 3	5,882	2,957	50%
Scenario 4	5,882	2,693	54%

⁷ While there is a limited supply of uncontracted large hydroelectric power, other operating CCEs have been successful in procuring this resource. To account for the limited supply, we added a 10% premium to the cost of this power.

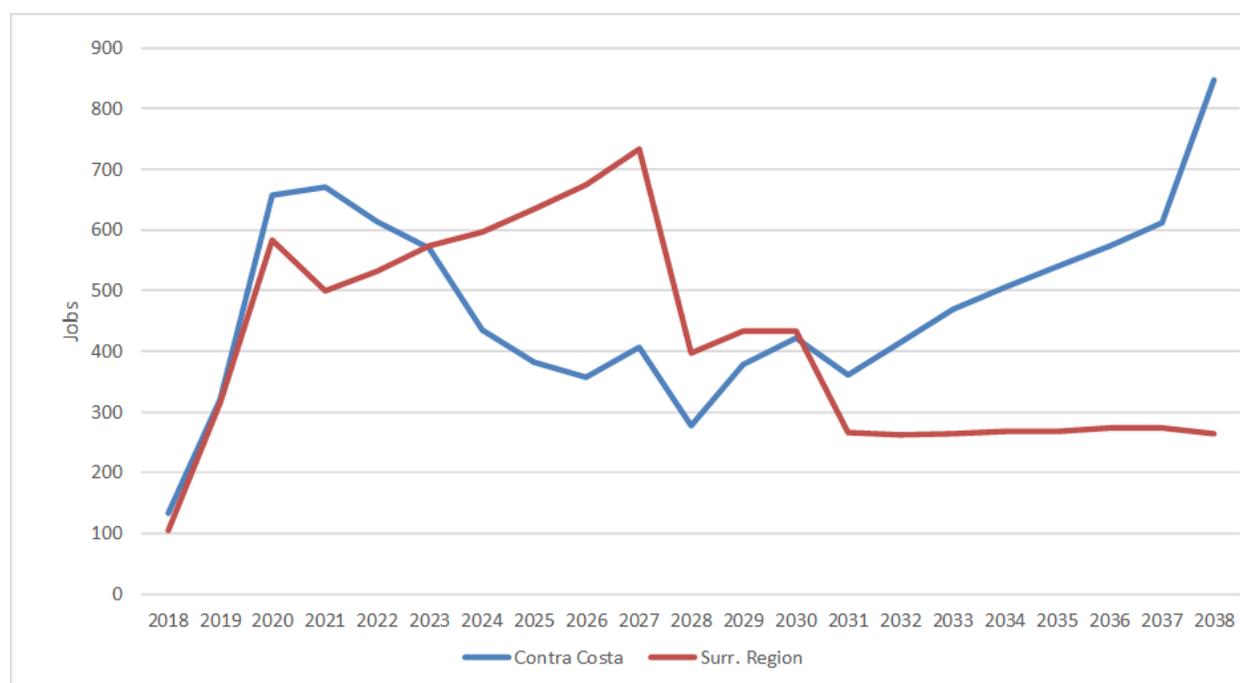
⁸ Thousands of metric tons.

Macroeconomic and Job Impacts

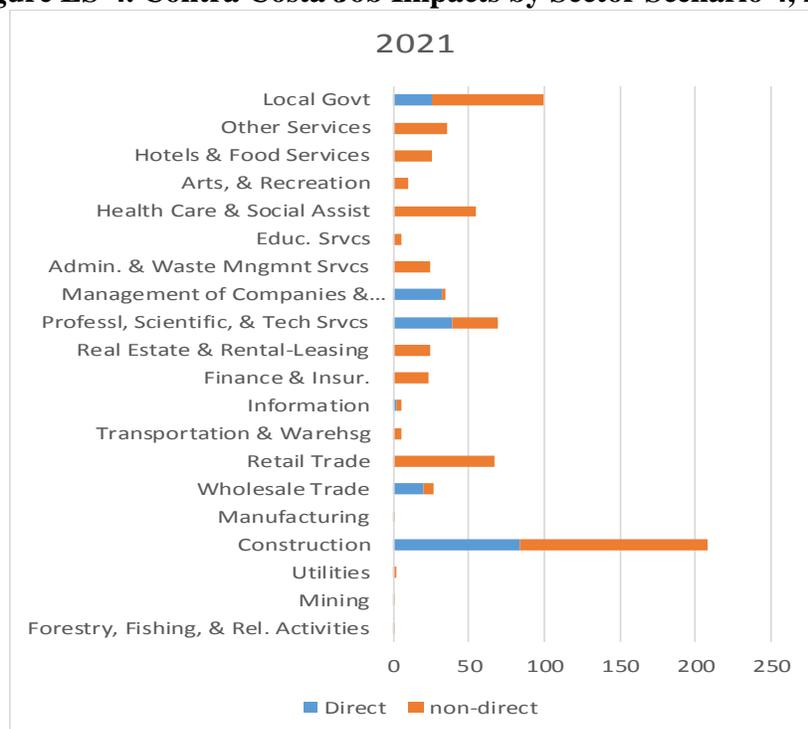
The local economic development and jobs impacts for the four scenarios were analyzed using the dynamic input-output macroeconomic model developed by Regional Economic Models, Inc. (REMI). The model accounts for not only the impact of direct CCE activities (e.g., local project installations for two of the four scenarios, program administration), but also how the rate savings that County households and businesses might experience with a CCE ripple through the local economy, creating more jobs and regional economic growth.

A CCE can also offer positive economic development and employment benefits to the County. The CCE could create approximately 500 to 700 additional annual jobs on average in the County plus an additional 50 to 400 jobs in the neighboring counties, depending on the scenario. The job impacts include not just the stimulus from program-related effects but jobs resulting from *multiplier effects* and *competitiveness effects*. Scenario 4 – with the smallest of *net* rate savings for the County’s electric customers contains the largest investment for small solar across the local economy. Figure ES-3 illustrates this through high-level results expressed as annual job changes for the Scenario 4.

Figure ES-3. Scenario 4 Regional Annual Jobs Impacts, 2018 to 2038



The economic activity generated by the CCE results in incremental employment in a variety of sectors. Figure ES-4 shows the estimated job impacts (direct and indirect) by sector for Scenario 4 in 2021 (the year in which the CCE’s assumed solar investment is maximum).

Figure ES-4. Contra Costa Job Impacts by Sector Scenario 4, 2021

Comparative Analysis of CCE Options

Having the County and cities within the County form their own Joint Powers Authority (JPA) and CCE Program is not the only possibility for CCE participation. First, the County and/or its cities may join MCE (formerly Marin Clean Energy). In fact, five cities in the County—El Cerrito, Lafayette, Richmond, San Pablo, and Walnut Creek—are already members of MCE. These cities joined between 2012 and 2016, and have full standing on MCE’s board of directors. Second, the County and/or its cities could join East Bay Community Energy (Alameda County, EBCE). While this CCE has just been formed—the JPA board met for the first time in January 2017—it intends to begin delivery of power in early 2018. Furthermore, the County and each city need not join one or the other CCE *en masse*, but instead can join one or the other CCEs individually (or neither).

Table ES-5 below provides a qualitative summary of the differences and similarities among these options. While a quantitative comparison would appear to provide more rigor, in this case it would provide only false precision. First and foremost, two of the potential CCE options are with entities which, while potentially viable, do not yet exist. Without power contracts, portfolios, or procurement guidelines and policies, it would be unwise to claim that EBCE or a potential Contra Costa-only CCE would have rates or greenhouse gas emissions higher or lower than the other. Comparisons against MCE can be somewhat more reasonably asserted; however, MCE’s stated goals—greater renewable energy content, lower greenhouse gas emissions, local generation, and comparable rates—are nearly identical to those stated by EBCE, making long-range rate and emissions distinctions immaterial. Thus, the qualitative comparisons provided in

the table do not provide sharp distinctions between the CCE options.⁹ All these options are expected to provide similar rates and GHG emissions, with differences arising from variations in the priorities and procurement decisions of the individual governance boards. What truly distinguishes these options are primarily governance options (i.e., in-county only versus shared with other entities) and the amount of risk assumed (i.e., developing or signing on with a new CCE versus joining one with a record of satisfactory performance).

Table ES-5. Comparison of Contra Costa CCE Options

Criterion	Form CCCo JPA	Join MCE	Join EBCE	Stay with PG&E
Rates	Likely lower	Likely Lower	Likely Lower	Base
GHG Reduction Potential Over Forecast Period	Some	Some	Some	Base
Local Control/Governance	Greatest	Some	Some	None
Local Economic Benefit Potential	Greatest	Some	Some	Minimal
Start Up Costs/Cost to Join	Low, but greater risk ¹⁰	None	None	None
Level of Effort	Greatest	Minimal	Greater	None
Program Risks	Greatest	Minimal	Some	Base
Timing (earliest)	Late-2018	Late-2017	Mid-2018	N/A

⁹ Differences between the CCE options and the option to stay with PG&E are more marked and better quantifiable, given that information on PG&E's power portfolios, procurement plans, and costs are at least partially available through various filings and applications PG&E has made before the CPUC. The comparisons provided above between the CCE's rates and PG&E's rates takes advantage of this information and market data on power procurement costs to develop quantitative comparisons between the CCE and PG&E options.

¹⁰ Start-up costs incurred by the County or others are likely to be reimbursed by the JPA.

Conclusions

Overall, a CCE in Contra Costa County appears feasible. Given current and expected market and regulatory conditions, a Contra Costa County CCE should be able to offer its residents and businesses electric rates that are less than those available from PG&E.

Sensitivity analyses suggest that these results are relatively robust. Only when very high amounts of local renewable energy are assumed in the CCE portfolio, combined with other negative factors such as higher PCIA rates, higher prices for local renewable power, or lower PG&E costs, do PG&E's rates become consistently more favorable than the CCE's.

A Contra Costa County CCE would also be well positioned to help facilitate greater amounts of renewable generation to be installed in the County. Because the CCE would have a much greater interest in developing local solar than PG&E, it is much more likely that such development would occur with a CCE in the County than without it.

The CCE can also reduce the amount of greenhouse gases emitted in the County if the CCE prioritizes this goal. Because PG&E's supply portfolio has significant carbon-free generation (from large hydroelectric and nuclear generators), the CCE would need to contract for significant amounts of hydroelectric or other carbon-free power above and beyond the required qualifying renewables to reduce the County's GHG footprint from electricity use. This analysis assumes that the CCE procures enough GHG-free generation to halve PG&E's GHG emissions rate, subject to constraints on the minimum share of market supplies in the CCE portfolio.

A CCE can also offer positive economic development and employment benefits to the County. At the peak, the CCE could create approximately 500 to 700 new jobs in the County plus additional jobs in neighboring counties. What may be surprising is that many of the economic benefits can come from reduced rates: residents and, more importantly, businesses can spend and reinvest their bill savings, and thus generate greater economic impacts.

While the analytical focus of this report has been on a stand-alone Contra Costa County CCE, that is not the only choice for Contra Costa communities (not already in MCE). Overall, there is insufficient data to suggest that a stand-alone Contra Costa CCE would offer lower rates or greater GHG savings than joining MCE or EBCE. Either forming or joining a CCE would likely offer modestly lower rates, more local economic development, and similar or lower GHG emissions than remaining with PG&E. Joining MCE would likely result in the quickest and least risky path to CCE implementation, however at a loss of local input into CCE policy formation. Because it has yet to be formed, joining with EBCE would take longer than joining the already-established MCE, but would offer greater input into the CCE's policies and formation.

Although all the CCE program options available to the jurisdictions studied would likely provide both environmental and economic benefits compared to PG&E, continuing service from PG&E remains an option for not only a community but also for any individual or business whose community has selected CCE service. PG&E is an experienced power provider and is regulated by the State. Furthermore, remaining with PG&E does not require the jurisdiction to take any action. Lastly, simply because a Contra Costa community does not join a CCE in 2017 or 2018 does not necessarily preclude it from doing so in the future, although waiting may result in an "entry fee" or perhaps a higher PCIA rate.

Chapter 1: Introduction

On March 15, 2016, the Contra Costa County (County) Board of Supervisors directed County staff to work with cities within the County to obtain electrical load data from the Pacific Gas and Electric Company (PG&E) for the purpose of conducting a technical study of options for implementing Community Choice Energy (CCE) within the County's unincorporated area and the 14 cities within the County not currently participating in a CCE program. The Board of Supervisors further directed the CCE technical study to compare the following alternatives for implementing CCE to the option of remaining with current electrical service from PG&E:

1. Form a new Joint Powers Authority (JPA) of the County and interested cities within Contra Costa County for the purpose of CCE;
2. Form a new JPA in partnership with Alameda County and interested cities in both counties; and
3. Join the existing CCE program initiated in Marin County, known as Marin Clean Energy (MCE).

The County and the 14 Contra Costa cities not currently participating in a CCE program all authorized the collection of load data from PG&E for this technical study. In addition, the County and the cities of Brentwood, Clayton, Concord, Martinez, Pleasant Hill, Pittsburg, and San Ramon, and the Towns of Danville and Moraga, contributed funding for the completion of this study.

What is a CCE?

California Assembly Bill 117, passed in 2002, established Community Choice Aggregation (also known as Community Choice Energy or "CCE") in California, for the purpose of providing the opportunity for local governments or special jurisdictions to procure or provide electric power for their residents and businesses.

Under existing rules administered by the California Public Utilities Commission (CPUC), PG&E must use its transmission and distribution system to deliver the electricity supplied by a CCE in a non-discriminatory manner. That is, it must provide these delivery services at the same price and at the same level of reliability to customers taking their power from a CCE as it does for its own full-service customers. By state law, PG&E also must provide all metering and billing services such that customers receive a single electric bill each month from PG&E, which would differentiate the charges for generation services provided by the CCE from the charges for PG&E delivery services. Money collected by PG&E on behalf of the CCE must be remitted in a timely fashion (e.g., within 3 business days).

As a power provider, the CCE must abide by the rules and regulations placed on it by the State and its regulating agencies, such as maintaining demonstrably reliable supplies, fully cooperating with the State's power grid operator, and meeting renewable procurement requirements. However, the State has no rate-setting authority over the CCE; the CCE may set rates as it sees fit so as to best serve its constituent customers.

Per California law, when a CCE is formed all the electric customers within its boundaries will be placed, by default, onto CCE service. However, customers retain the right to return to PG&E service at will, subject to whatever administrative fees the CCE may choose to impose.

California currently has five active CCE Programs: MCE, serving Marin County and selected neighboring jurisdictions, including five cities in Contra Costa County; Sonoma Clean Power, serving Sonoma County; CleanPowerSF, serving San Francisco City and County; Peninsula Clean Energy, serving San Mateo County; and Lancaster Choice Energy, serving the City of Lancaster (Los Angeles County). Numerous other local governments are also investigating CCE formation, including Alameda County; Los Angeles County; Monterey Bay region; Santa Barbara, San Luis Obispo and Ventura Counties; ; the City of Davis and Yolo County; and Humboldt County to name a few.

Assessing CCE Feasibility

In order to assess whether a CCE is “feasible” in Contra Costa County, the local objectives must be laid out and understood. Based on the specifications of the initial request for proposals and input from the County, this study:

- Quantifies the electric loads that a Contra Costa County CCE would serve;
- Estimates the costs to start-up and operate the CCE;
- Considers four scenarios with differing assumptions concerning the amount of GHG-free power and local renewable power being supplied to the CCE so as to assess the costs, greenhouse gas emissions reductions, and local economic development opportunities possible with the CCE;
- Includes analysis of in-county renewable generation;
- Compares the rates that could be offered by the CCE to PG&E’s rates;
- Quantitatively explores the rate competitiveness of the four scenarios to key input variables, such as the cost of natural gas;
- Calculates the macroeconomic development and employment benefits of CCE formation; and
- Compares the benefits and risks of forming a CCE or joining a neighboring CCE versus remaining on PG&E bundled service.

For comparison, the differences in the results between this study and that conducted for Alameda County will be described and underlying reasons explained.

The communities constituting the “Contra Costa CCE” in this study are: Antioch, Brentwood, Clayton, Concord, Danville, Hercules, Martinez, Moraga, Oakley, Orinda, Pinole, Pittsburg, Pleasant Hill, San Ramon, and unincorporated County. They do not include the communities already being served by the Community Choice Energy provider MCE (El Cerrito, Lafayette, San Pablo, Richmond and Walnut Creek).

This study was conducted by MRW & Associates, LLC (MRW). MRW was assisted by Sage Renewables, which conducted the local renewable energy potential study, and by Economic Development Research Group, which conducted the macroeconomic and jobs analysis contained in the study.

This study is based on the best information available at the time of its preparation, using publicly available sources for all assumptions to provide an objective assessment regarding the prospects of CCE operation in the County. It is important to keep in mind that the findings and recommendations reflected herein are substantially influenced by current market conditions within the electric utility industry, which are subject to sudden and significant changes.

Chapter 2: Economic Study Methodology and Key Inputs

This Chapter summarizes the key inputs and methodologies used to evaluate the cost-effectiveness and cost-competitiveness of a Contra Costa CCE relative to PG&E under different scenarios.¹¹ It considers the regulatory requirements that a Contra Costa County CCE would need to meet (e.g., compliance with renewable portfolio standard (RPS) requirements), the resources that the County has available or could obtain to meet these requirements, and the PG&E rates against which the CCE would compete. It also describes the pro forma analysis methodology that is used to evaluate the financial feasibility of the CCE.

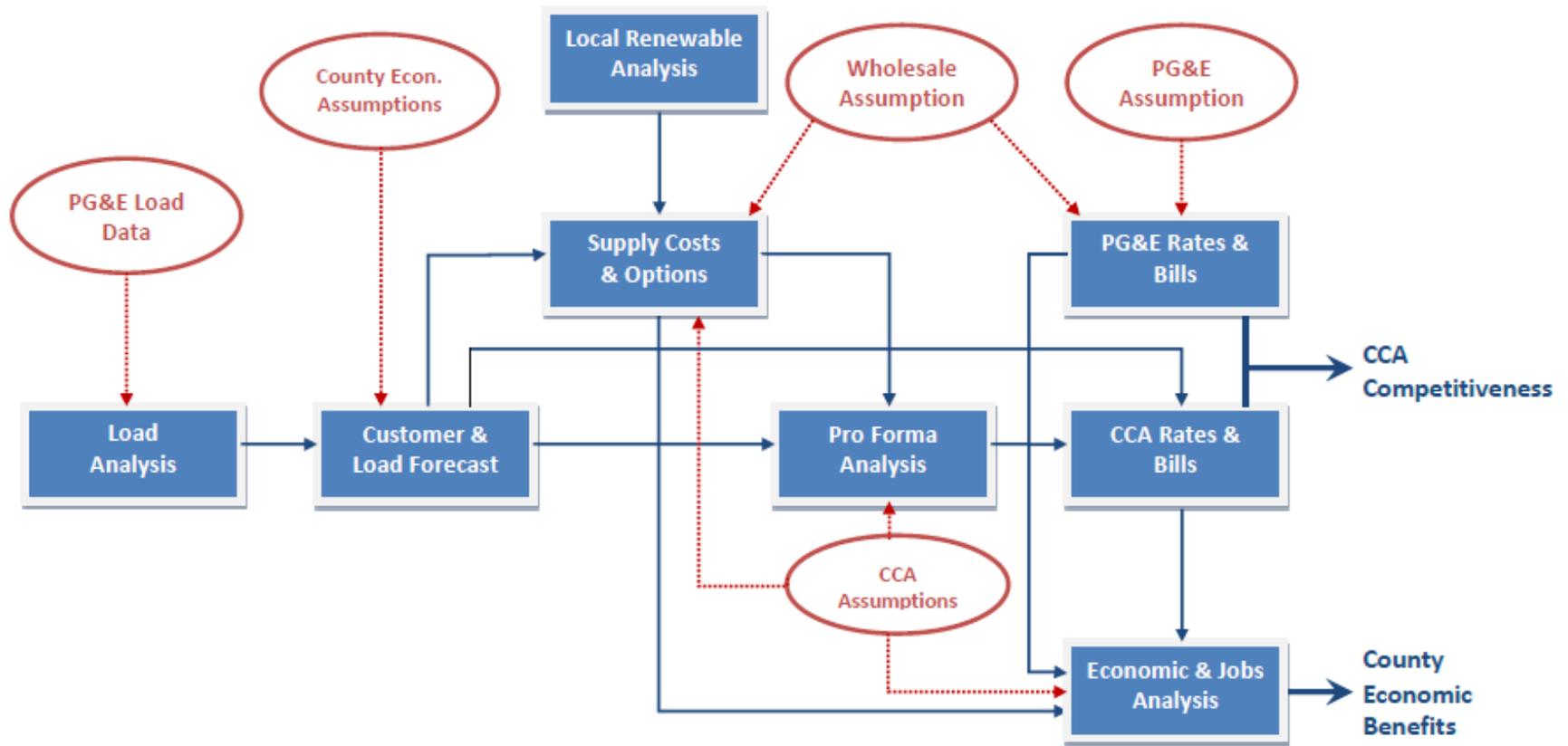
The load and rate forecasts go out twenty years—through 2038. While all forecasting contains an element of uncertainty, the years beyond 2030 are particularly uncertain and should be seen as broadly indicative and not predictive.

Understanding the interrelationships of all the tasks and using consistent and coherent assumptions throughout are critical to developing a meaningful analysis. Figure 1 shows the analysis elements (blue boxes) and major assumptions (red ovals) and how they relate to each other. As the figure illustrates, there are numerous interrelationships between the tasks. For example, the load forecast is a function of not only the load analysis, but also of projections of economic activity in the County.

Two important points are highlighted in this figure. First, it is critical that wholesale power market assumptions are consistent between the CCE and PG&E. While there are reasons that one might have lower or higher costs than the other for a particular product (e.g., CCEs can use tax-free debt to finance generation projects while PG&E cannot), both will participate in the wider Western U.S. gas and power markets and therefore will be subject to the same underlying market forces. Applying different power cost assumptions to the CCE than to PG&E, such as simply escalating PG&E rates while deriving the CCE rates using a bottom-up approach, would produce erroneous results. Second, virtually all elements of the analysis feed into the economic and jobs assessment. As is described in detail in Chapter 5, this Study uses a state-of-the-art macroeconomic model that can account for numerous activities in the economy, which allows for a much more comprehensive—and accurate—assessment than a simple input-output model.

¹¹ The relative costs and merits of joining CCEs in neighboring counties are addressed in Chapter 7.)

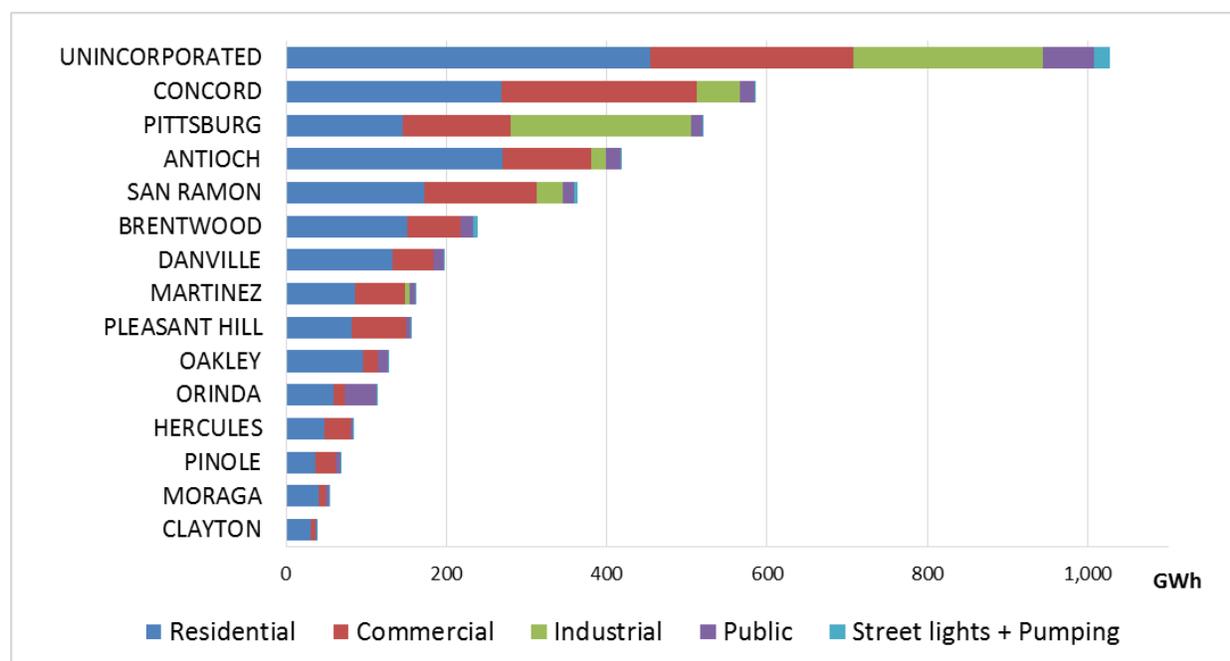
Figure 1. Task Map



Contra Costa County Loads and CCE Load Forecasts

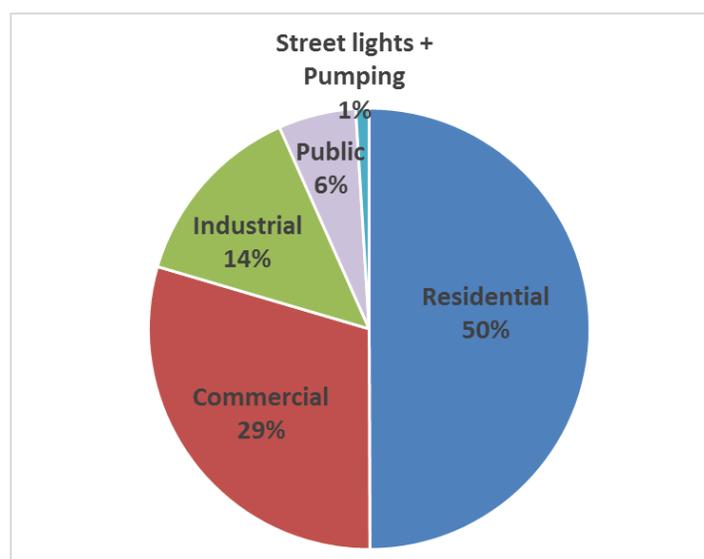
MRW used PG&E bills from 2015 for all PG&E bundled service customers within the Contra Costa County region as the starting point for developing electrical load and peak demand forecasts for the Contra Costa County CCE program.¹² Figure 2 provides a snapshot of Contra Costa County bundled load in 2015 by city and by rate class. PG&E's total electricity load in 2015 from these customers was approximately 4,000 GWh.¹³ The unincorporated areas of the County represented 25% of County load, and the cities of Concord and Pittsburg were together responsible for another 25%. Residential and commercial customers made up most of the County load, with smaller contributions from the industrial and public sectors (Figure 3). This same sector-level distribution of load is also apparent at the jurisdictional level for most cities (Figure 2), except for the City of Pittsburg, which has a significant industrial-sector footprint.

Figure 2. PG&E's 2015 Bundled Load in Contra Costa County by Jurisdiction and Rate Class



¹² Detailed monthly usage data provided by PG&E to Contra Costa County. "Bundled" load includes only load for which PG&E supplies the power; it excludes load from Direct Access customers, load in the jurisdiction of another CCE provider, and load met by customer self-generation. This excludes load originating in the cities of El Cerrito, Lafayette, Richmond, San Pablo, and Walnut Creek, which are served by MCE.

¹³ As determined from bill data provided by PG&E.

Figure 3. PG&E's 2015 Bundled Load in Contra Costa County by Rate Class

To estimate CCE loads from PG&E's 2015 bundled loads, MRW assumed a CCE participation rate of 85% (i.e., 15% of customers opt to stay with PG&E) and a three-year phase in period from 2018 to 2020, with 33% of potential CCE load included in the CCE in 2018, 67% in 2019, and 100% in 2020. To forecast CCE loads through 2038, MRW used a 0.4% annual average growth rate, consistent with the California Energy Commission's most recent electricity demand forecast for PG&E's planning area.¹⁴ The CCE load forecast is summarized in Figure 4, which shows annual projected CCE loads by class.

To estimate the CCE's peak demand in 2015,¹⁵ MRW multiplied the load forecast for each customer class by PG&E's 2015 hourly ratio of peak demand to load for that customer class.¹⁶ MRW extended the peak demand forecast to 2038 using the same growth rates used for the load forecast. The peak demand forecast is summarized in Figure 5.

¹⁴ California Energy Commission. Form 1.1c California Energy Demand Updated Forecast, 2015 - 2025, Mid Demand Baseline Case, Mid AAEE Savings. January 20, 2015

http://www.energy.ca.gov/2014_energypolicy/documents/demand_forecast_cmf/LSE_and_BA/

¹⁵ Peak demand is the maximum amount of power the CCE would use at any time during the year. It is measured in megawatts (MW). The CCE must have enough power plants on (or contracted with) at all times to meet 115% of the expected peak demand.

¹⁶ Data obtained from PG&E's dynamic load profiles for Public, Industrial, Commercial, and Residential customers (https://www.pge.com/nots/rates/tariffs/energy_use_prices.shtml) and static load profiles for Pumping and Streetlight customers (https://www.pge.com/nots/rates/2016_static.shtml#topic2).

Figure 4: CCE Load Forecast by Class, 2018-2038¹⁷

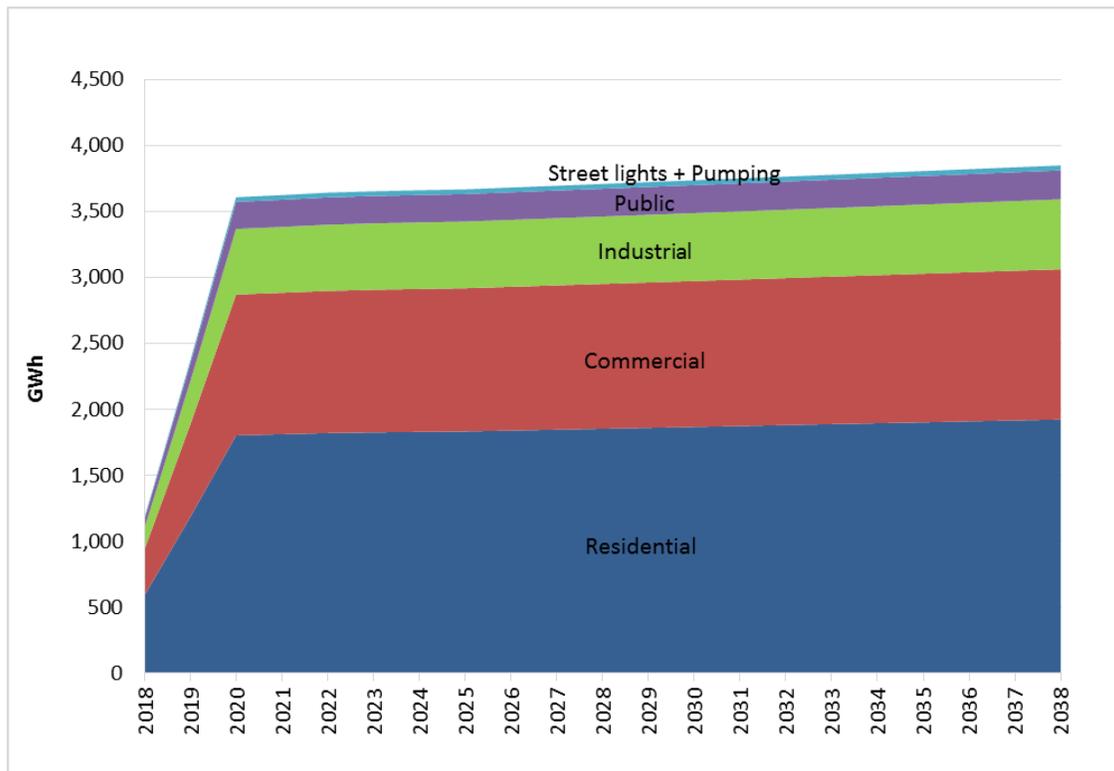
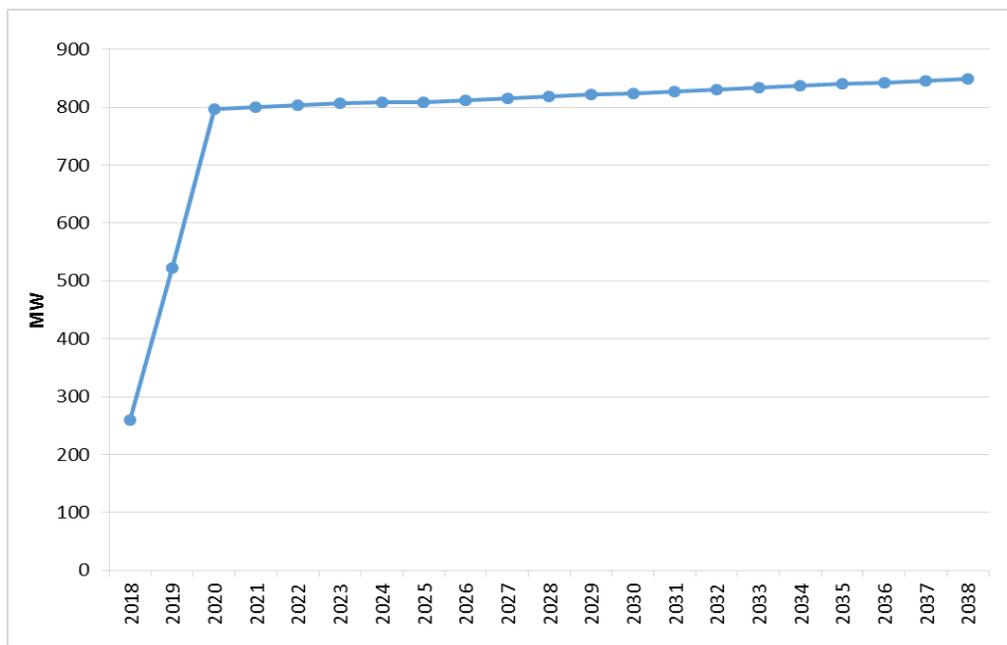


Figure 5. CCE Peak Demand Forecast, 2017-2038



¹⁷ Load forecasted assumes 85% participation and three-year phase-in.

CCE Supplies

The CCE's primary function is to procure supplies to meet the electrical loads of its customers. This requires balancing energy supply and demand on an hourly basis. It also requires procuring generating capacity (i.e., the ability to provide energy when needed) to ensure that customer loads can be met reliably.¹⁸ In addition to meeting the energy and capacity needs of its customers, the CCE must meet other procurement objectives. By law, the CCE must supply a certain portion of its sales to customers from eligible renewable resources. This Renewable Portfolio Standard (RPS) requires 33% renewable energy supply by 2020, increasing incrementally to 50% by 2030. According to PG&E's Diablo Canyon nuclear plant retirement application, PG&E may commit to purchasing additional renewable supply, targeting up to 55% of the total generation between 2030 and 2038, which the CCE would presumably at least match. The CCE may additionally choose to source a greater share of its supply from renewable sources than the minimum requirements, or may seek to otherwise reduce the environmental impact of its supply portfolio. The CCE may also use its procurement function to meet other objectives, such as sourcing a portion of its supply from local projects to promote economic development in the County.

The Contra Costa County CCE would be taking over these procurement responsibilities from PG&E for those customers who do not opt out of the CCE to remain bundled customers of PG&E. To retain customers, the CCE's offerings and rates must compete favorably with those of PG&E.

The CCE's specific procurement objectives, and its strategy for meeting those objectives, will be determined by the CCE through an implementation plan, startup activities, and ongoing management of the CCE. A primary purpose of this portion of the study is to assess the feasibility of establishing a CCE to serve Contra Costa County based on a forecast of costs and benefits. This forecast requires making certain assumptions about how the CCE will operate and the objectives it will pursue. To address the uncertainty associated with these assumptions, we have evaluated four different supply scenarios and have generally made conservative assumptions about the ways in which the CCE would meet the objectives discussed above. In no way does this study prescribe actions to be taken by the CCE should one be established.

The four supply scenarios that we considered in this analysis are summarized in Table 1 and are described as follows:

1. **Minimum RPS Compliance:** The CCE meets the mandated 33% RPS requirement in 2020 and the 50% RPS requirement in 2030, plus the 55% RPS target after 2030. Annual GHG emissions from the CCE portfolio are halved relative to PG&E's bundled portfolio

¹⁸ The California Public Utilities Commission requires that CCEs and other load serving entities demonstrate that they have procured resource adequacy capacity to meet at least 115% of their expected peak load. Because Contra Costa County falls within the Greater Bay Area Local Reliability Area, the Contra Costa County CCE must also meet its share of local resource adequacy requirements.

through the addition of large hydroelectric power purchases, subject to a constraint that 5% of the CCE supply come from non-renewable market sources.^{19,20}

2. **Accelerated RPS:** The CCE’s supply portfolio is set at 50% RPS in the first year and increases to 80% RPS by 2030. As in Scenario 1, the remaining supply is a mix of hydroelectric power and market purchases aimed at halving PG&E’s annual emissions subject to a 5% minimum supply from market purchases.
3. **Minimum RPS Compliance plus Local:** The CCE meets the mandated 33% RPS requirement in 2020 and the 50% RPS requirement in 2030, plus the 55% RPS target after 2030. In addition, 50% of the total RPS generation is provided by local resources by 2030. Large hydroelectric and market supplies, and thus GHG emissions, are the same as in Scenario 1.
4. **Accelerated RPS plus Local:** The CCE’s supply portfolio is set at 50% RPS in the first year and increases to 80% RPS by 2030. In addition, 50% of the total RPS generation is provided by local resources by 2030. Large hydroelectric and market supplies, and thus GHG emissions, are the same as in Scenario 2.

Table 1: RPS-Eligible Procurement and GHG Emissions in Each Scenario²¹

	Scenario 1	Scenario 2	Scenario 3	Scenario 4
Percent RPS-Eligible in 2020	33%	50%	33%	50%
Percent RPS-Eligible in 2030	50%	80%	50%	80%
Share of RPS-Eligible from Local Resources	0%	0%	50%	50%
GHG Emissions compared to PG&E	50% Lower	54% Lower	50% Lower	54% Lower

¹⁹ For all scenarios we assume a minimum 5% non-renewable market supply to reflect operating constraints that require flexible, dispatchable generation on the system and in local areas. The CCE may be able to reduce emissions further through the use of energy storage or other measures to reduce the need for non-renewable power supplies, likely at additional cost.

²⁰ The availability and cost risks of large hydropower are discussed in Chapter 6, Impact of High CCE Penetration on Low-Carbon (Hydro) Resources.

²¹ Customer-sited solar is not considered RPS-eligible in California and is not included in the RPS procurement in these scenarios. Customer-sited solar is incorporated in this analysis as a reduction to the CCE’s load.

To evaluate these scenarios, we assumed a simple portfolio consisting of RPS-eligible resources and additional GHG-free resources in an amount dictated by the particular scenario, with the balance of supply provided by non-renewable wholesale market purchases. In each case, we assumed that the RPS portfolio was predominately supplied with solar and wind resources, which are currently the low-cost sources of renewable energy. We assumed that solar and wind each contribute 45% of the renewable energy supply on an annual basis. To provide resource diversity and partly address the need for supply at times when solar and wind production are low, we assumed the remaining 10% of renewable supply would be provided by higher-cost baseload renewable resources, such as geothermal or biomass.

In the early years, the CCE would have to purchase its required renewable power from the market and existing resources. However, the study assumes that the CCE would contract with new renewable resources, such that by 2030 most of its renewable power would come from new resources. Figures 6 and 7 show the assumed build-out of these new resources under the first (Minimum RPS Compliance) and the fourth (Accelerated RPS plus Local) scenarios described above.

Figure 6. Scenario 1 CCE Build-Out

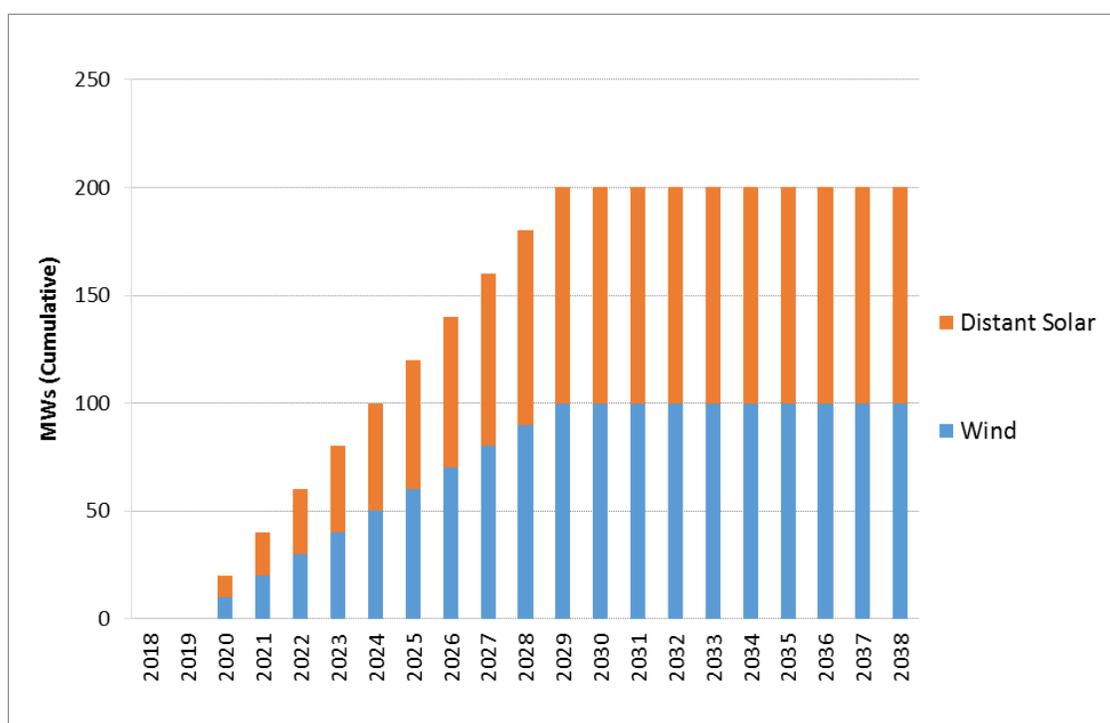
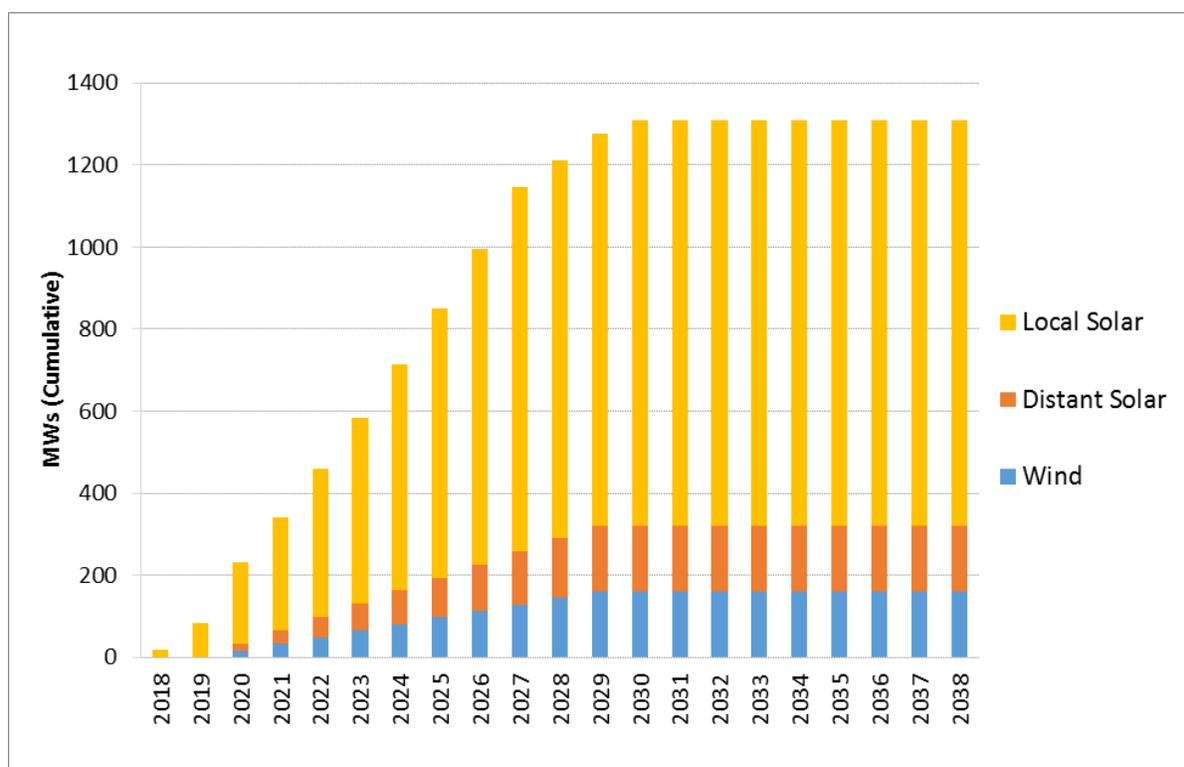
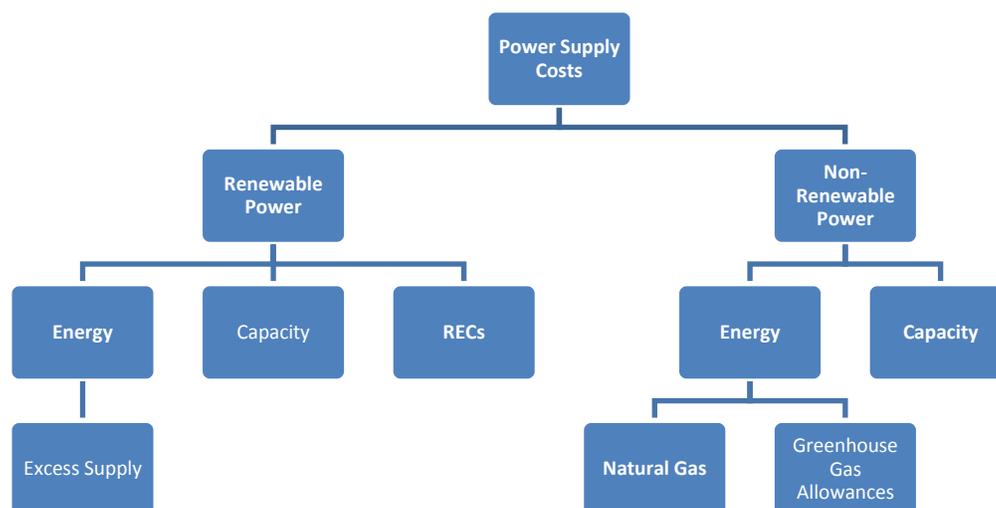


Figure 7. Scenario 4 CCE Build-Out

Power Supply Cost Assumptions

As discussed above, the CCE would procure a portfolio of resources to meet its customers' needs, which would consist of a mix of renewable and non-renewable (i.e., wholesale market) resources. As shown in Figure 8, the products to be purchased by the CCE consist generally of energy, capacity, and renewable attributes (which for counting purposes take the form of renewable energy credits, or Category 1 RECs).²²

²² RECs are typically bundled with energy deliveries from renewable energy projects, with each REC representing 1 MWh of renewable energy. A limited number of unbundled RECs may be used to meet RPS requirements. For the purpose of this study we have not considered unbundled RECs and have rather estimated costs based on renewable energy contracts where the RECs are bundled.

Figure 8. Power Supply Cost Elements

The CCE will procure supplies from the same competitive market for resources as PG&E. Thus, we assume that the costs for renewable and non-renewable energy and for resource adequacy (RA) capacity for the CCE are the same as for new purchases made by PG&E (discussed further in our forecast of PG&E rates). Wholesale market prices for electricity in California are largely driven by the cost of operating natural gas power plants, as these plants typically have the highest operating costs and are the marginal units. Market prices are a function of the efficiency of the marginal generators, the price of natural gas, and the cost of GHG allowances. MRW developed forecasts of these elements to derive a power price forecast to determine costs for the CCE and PG&E. Large hydroelectric power prices are based on the market price forecast with a 10% premium to reflect the value of GHG benefits, flexibility, and increasing demand from load serving entities seeking clean power like the CCE. Capacity prices are based on prices for RA contracts reported by the CPUC and on the cost to build a new combustion turbine power plant.

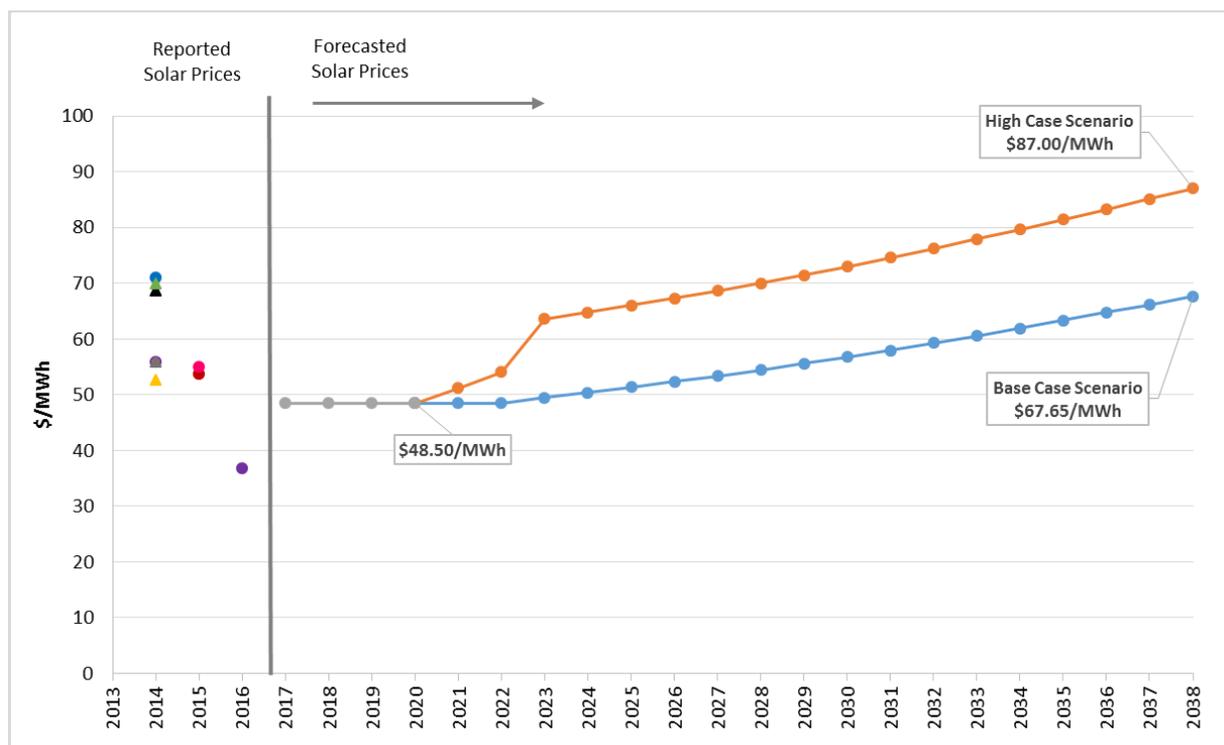
MRW developed a forecast of non-local utility scale renewable generation prices starting from an assessment of the current market price for renewable power. For the current market price, MRW relied on wind and solar contract prices reported by California municipal utilities and CCEs in 2015 and early 2016, finding an average price of \$49/MWh for the solar contracts, \$55/MWh for wind power and \$80/MWh for geothermal.²³ We used these prices as the starting point for our forecast of CCE renewable energy procurement costs. For geothermal, which is a

²³ MRW relied exclusively on prices from municipal utilities and CCEs because investor-owned utility contract prices from this period are not yet public. We included all reported wind and solar power purchase agreements, excluding local builds (which generally come at a price premium), as reported in *California Energy Markets*, an independent news service from Energy Newsdata, from January 2015-January 2016 (see issues dated July 31, August 14, October 16, October 30, 2015, and January 15, 2016).

relatively mature technology, we assumed that new contract prices would simply escalate with inflation.

Solar and wind prices are a function of technology costs, which have generally been declining over time; financing costs, which have been very low in recent years; and tax incentives, which significantly reduce project costs, but phase out over time. In the near-term we would not expect prices to increase as technology costs and continued tax incentives provide downward pressure and likely offset any increase in financing costs or other competitive pressure from an increasing demand for renewable energy in California. For utility scale wind prices, we relied on an expert elicitation survey²⁴ developed by Lawrence Berkeley National Laboratory (LBNL). According to this survey, wind prices will decrease 24% by 2030 and 35% by 2050.²⁵ For solar, we held prices constant in nominal dollars through 2020. Beyond 2020, with increasing competitive pressure due to the drive to a 50% RPS and the anticipated phase-out of federal tax incentives (offset in part by declining technology costs), we would expect prices to increase somewhat and have assumed they escalate at the rate of inflation. In addition, we also considered a high solar cost scenario based on work performed by LBNL on the value of tax incentives. In the high scenario, we assume that costs increase with the phase-out of federal tax incentives, without being offset by declining technology costs. Figure 9 shows the resulting solar price forecasts for the two scenarios.

Figure 9. Large-Scale Non-Local Solar Price Forecast



²⁴ “Expert Elicitation Survey of Future Wind and Energy Costs,” *Nature Energy*, September 12, 2016.

²⁵ Relative to the 2014 wind prices. MRW also added the annual inflation increase.

Local Solar Analysis

Pivotal to the evaluation of the local economic impacts of a Contra Costa CCE is an understanding of how much renewable energy can be developed within the County. This assessment focused on identifying local solar photovoltaic (PV) siting potential. Wind and biomass energy were also evaluated, but were determined to be less feasible for Contra Costa County.

The solar PV assessment is based on a comprehensive desktop review of countywide parcel data, geographic features, and solar energy potential. Table 2 shows the total solar PV generation capacity within the County based on the methodology and assumptions described below.

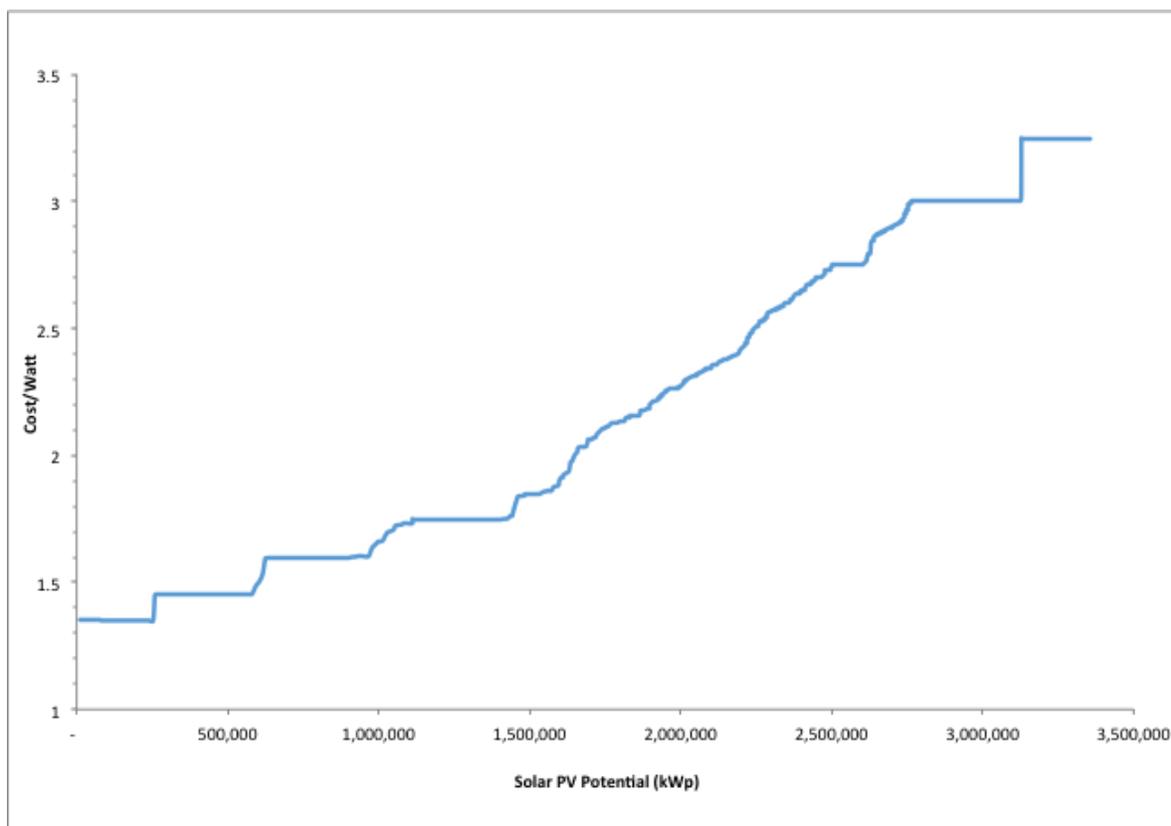
Table 2. Total PV Solar Generation Potential and Build Cost

	Ground Mount	Shade Structure	Roof Mounted	Total
PV Capacity (MW²⁶)	1,891	1,320	144	3,355
PV Production (GWh)	3,025	2,113	230	5,369
Build Cost (\$ Millions)	\$3,417	\$3,977	\$371	\$7,660
Build Cost (\$/Watt)	\$1.99	\$3.10	\$2.62	\$2.56
No. of PV Systems	845	886	144	1,875

Generation capacity was determined for the three types of possible solar PV installations: Ground-Mount, Shade Structure/Carport, and Roof Mount. The findings show that the County has a solar PV generation capacity of 3,355 MW and annual solar electricity production potential of 5,369 GWh. Figure 10 shows the aggregate Solar PV supply curve for all County jurisdictions.

Note that the costs shown in Table 2 and Figure 10 are “build costs.” Additional soft costs, particularly the acquisition or opportunity cost of the land upon which the ground-mount solar is located, are highly site-specific and not included in these values. These can add up to 50% to the cost of local solar projects, and are accounted for in the CCE scenario modeling.

²⁶ Local solar PV capacity measured at the panel (i.e., pre-inverter).

Figure 10. Aggregate Solar PV Supply Build Cost Curve, All County**Siting Analysis**

To assess the potential locations in Contra Costa County where solar PV could be developed, this study utilized a Geographic Information System (GIS)-based desktop review, incorporating aerial imagery and land-based data. The collected data was analyzed and potential solar PV development sites were identified from criteria established through industry knowledge and input from County stakeholders.

The agreed upon criteria are as follows:

- The minimum acceptable parcel size is three acres. Smaller parcels will not be able to hold an economically viable project. If a potential solar PV system size is below 500 kW it was excluded from the list of potentially feasible sites and overall solar energy capacity.²⁷ Again, this measure ensures only realistic and economically feasible sites are identified.
- Based on input from the County, only specific tax codes and zoning areas were evaluated. For example, areas such as Open Space or Parks have sufficient land area for solar PV

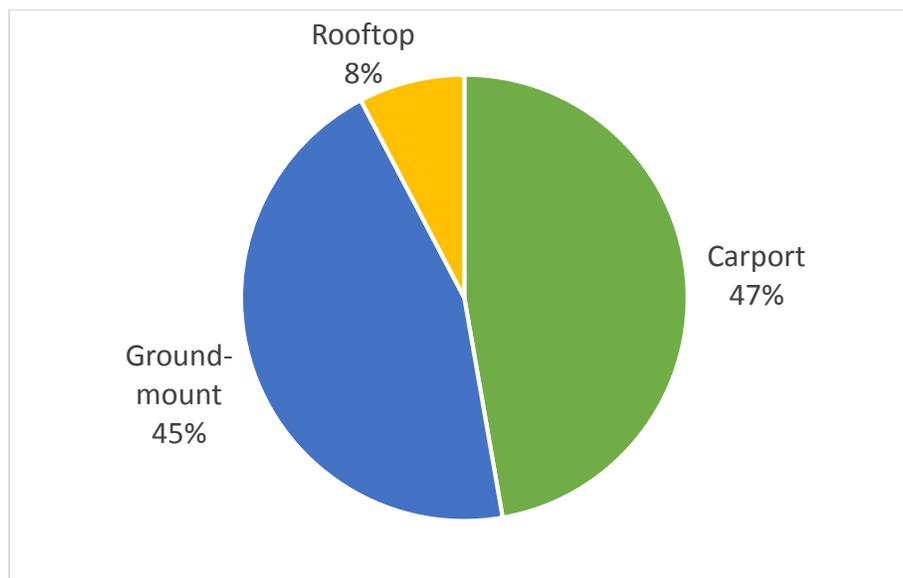
²⁷ Residential and other small rooftop solar are accounted for in the California Energy Commission sales forecast used to develop the CCE's demand forecast.

projects, but zoning restrictions would not allow for the development of these projects, and these areas were removed from the approved scope.

- In addition to size and tax/zoning code designations, areas with poor ground quality (marshland), excessive tree density, or excessive sloping would prohibit cost-effective solar PV development and were removed from the analysis.
- Lastly, sites with existing solar were removed from the pool of potential parcels/sites.

Within each identified parcel is the potential for three different types of solar PV development. On impervious land, such as a parking lot, it was assumed that solar PV carports would be installed. On grassland or bare land areas, this analysis assumed a ground-mounted solar PV system would be installed. Lastly, roof-mounted solar PV was assumed for any buildings found in the parcel data that matched the approved criteria. Countywide, 92% of potential installation sites were found to be either carport or ground-mount sites, with only 8% of the sites amenable to roof-mounted PV (Figure 11). The size of the estimated solar PV system was found by analyzing the total land area against the needed land required for solar PV development.

Figure 11. Potential Solar PV Sites by Installation Type



This study found 1,395 parcels that met the established criteria and 1,875 individual sites within the identified parcels where either a solar shade structure, rooftop, or ground-mounted system could be developed. Table 3 shows the individual sites organized by type of solar PV system for each jurisdiction in Contra Costa County.²⁸

This assessment also calculated the amount of solar energy production for each of the potential sites identified. The amount of energy production was found by multiplying the estimated system size by an average solar yield. The average solar energy yield was created by designing sample projects that matched the estimated system size in the solar software platform Helioscope. Because Contra Costa County has a variety of solar exposure, multiple sites across the County were designed/tested to find an average yield. Based on our testing, the average yield for Contra Costa County is 1,600 (kWh/kW). The resulting amount of potential PV production per jurisdiction is also provided in Table 3.

²⁸ For maps, please see

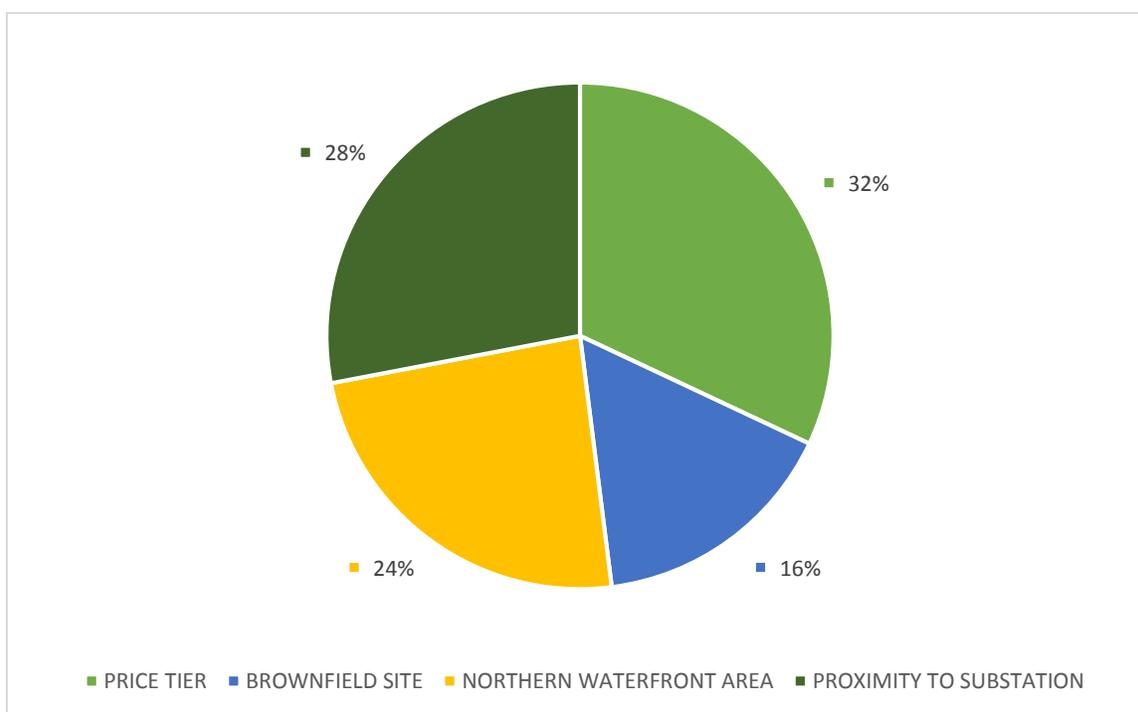
<https://www.dropbox.com/s/cb3rig66shny68j/Contra%20Costa%20CCE%20Solar%20Siting%20DRAFT%20Report%20SA%202016-11-15%20Reduced%20Size.pdf?dl=0>.

Table 3. Potential PV Production and Build Cost by Location

Jurisdiction	PV Potential (MW)	PV Production (GWh)	Build Cost (\$ Millions)
Alamo	14	23	\$30,779,000
Antioch	462	739	\$1,010,374,000
Brentwood	287	460	\$599,685,000
Clayton	38	62	\$71,171,000
Concord	370	593	\$900,603,000
Crockett	58	93	\$125,187,000
Danville	80	129	\$177,801,000
El Cerrito	29	48	\$73,161,000
El Sobrante	19	31	\$42,020,000
Hercules	90	144	\$200,511,000
Lafayette	8	13	\$23,641,000
Martinez	313	502	\$654,701,000
Moraga	24	39	\$55,957,000
Oakley	121	194	\$285,786,000
Orinda	22	36	\$43,554,000
Pinole	47	77	\$126,870,000
Pittsburg	314	502	\$705,202,000
Pleasant Hill	60	96	\$164,364,000
Port Costa	8	13	\$13,501,000
Richmond	502	804	\$1,261,541,000
Rodeo	35	57	\$85,874,000
San Pablo	191	307	\$459,784,000
San Ramon	158	254	\$384,634,000
Walnut Creek	95	152	\$269,795,000
Grand Total	3,355	5,369	\$7,766,496,000

Ranking

After the feasible solar sites and the corresponding solar PV capacity were identified, each site was ranked. The ranking was weighted based on how important it was to the actual feasibility of developing the site for solar PV and based on input from County stakeholders. The ranking consisted of the following measures as shown in the figure below.

Figure 12. Weighted Ranking Categories

An overall ranking score was then applied to each individual site to illustrate the best and worst sites for solar PV development. Sites were then grouped in tiers one through five, with one being the best. In addition to the ranking score, industry knowledge indicates the best sites to develop a feasible solar PV project will be larger than 1 MW, located on government land, and will be a ground-mounted solar array, the most cost-effective installation type. The table below shows the key characteristics of the ranking analysis.

Table 4. Ranking Values for All Sites

Ranking Tier	Sum of PV Production (GWh)	Sum of Total Price	Average Build Price per Watt
1	1,309	\$1,591,810,000	\$2.13
2	1,167	\$1,578,770,000	\$2.37
3	1,105	\$1,622,236,000	\$2.57
4	868	\$1,251,547,000	\$2.56
5	919	\$1,722,142,000	\$3.07

Local Solar Modeled in the CCE Scenarios

To estimate the contribution of local solar to a Contra Costa CCE's supply costs, we used the supply curve shown in Figure 10. To translate the \$/kW costs in the figure to \$/MWh generation costs, we used the pro forma model contained in the CPUC's RPS Calculator and the cost and performance assumptions provided by Sage for the County. For example, the lowest-cost projects at \$1,350/kW were estimated to have a generation cost of \$98/MWh (\$68/MWh for build costs and \$30/MWh for soft and land acquisition/opportunity costs).

The generation cost was assumed to scale with installed cost. Because it is unlikely that all the identified sites would be developed in order of their increasing cost (and some sites may never be developed regardless of economics), we assumed that 50% of the capacity identified in the cost curve would be developed for the purpose of conservatively estimating average costs at each level of local solar penetration. We calculated the average price for the cumulative developed capacity forecast for each year (again, counting only 50% of the capacity of each developed project towards the cumulative total). For Scenarios 3 and 4, we assumed that 50% of the CCA's RPS supply would be provided by local solar by 2027, adding 620 MW of local solar under Scenario 3 and 990 MW under Scenario 4 by 2030. (Scenarios 1 and 2 do not include any local solar.)

Greenhouse Gas Costs

MRW estimated that the price of GHG allowances would equal the auction floor price stipulated by the California Air Resources Board's cap-and-trade regulations, consistent with recent auction outcomes.²⁹

Table 5. GHG Allowances price³⁰

	2017	2018	2019	2025	2030	2035	2038
\$/tonne	13.2	14.7	15.9	24.4	34.7	49.8	61.8

Total GHG costs were calculated by multiplying the allowance price by the amount of carbon emitted per megawatt-hour for each assumed resource. For "system" purchases, MRW assumed that the GHG emissions corresponded to a natural gas generator operating at the market heat rate. This worked out to be, on average over 2018-2038, approximately \$1.5/MWh delivered.³¹

Other CCE Supply Costs

The CCE is expected to incur additional costs associated with its procurement function. For example, if the CCE relies on a third-party energy marketing company to manage its portfolio it will likely incur broker fees or other expenses equal to roughly 5% of the forecasted contract costs. The CCE would also incur costs charged by the California Independent System Operator

²⁹ California Code of Regulations, Title 17, Article 5, Section 95911. Auction results available at http://www.arb.ca.gov/cc/capandtrade/auction/results_summary.pdf.

³⁰ For 2017, the amount listed corresponds to the GHG allowance price for PG&E according to the most recent ERRA 2017 update. Pacific Gas & Electric ERRA 2017, A.16-06-003, Testimony November 2, 2016, Table 12-1.

³¹ The amount of GHG emissions will depend on the generation portfolio. \$1.50/MWh corresponds to the GHG emissions costs under Scenario 1.

(CAISO) for ancillary services (activities required to ensure reliability) and other expenses. MRW added 5.5% to the CCE's power supply cost to cover these CAISO costs. Finally, we added an expense associated with managing the CCE's renewable supply portfolio. Based on an analysis of the expected CCE load shape and the typical generation profile of California solar and wind resources, we observed that there will be hours in which the expected deliveries from renewable contracts will be greater than the CCE's load in that hour. This results from the amount of renewable capacity that must be contracted to meet annual RPS targets and the variability in renewable generation that leads to higher deliveries in some hours and lower deliveries in other hours. When high renewable energy deliveries coincide with low loads, the CCE will need to sell the excess energy, likely at a loss, or curtail deliveries, and will potentially have to make up those renewable energy purchases during higher load hours to comply with the RPS. The result is that the procurement costs will be somewhat higher than simply contracting with sufficient capacity to meet the annual RPS.

PG&E Rate and Exit Fee Forecasts

MRW developed a forecast of PG&E's bundled generation rates and CCE exit fees in order to compare the projected rates that customers would pay as Contra Costa County CCE customers to the projected rates and fees they would pay as bundled PG&E customers.

PG&E Bundled Generation Rates

To ensure a consistent and reliable financial analysis, MRW developed a 20-year forecast of PG&E's bundled generation rates using market prices for renewable energy purchases, market power purchases, greenhouse gas allowances, and capacity that are consistent with those used in the forecast of Contra Costa County CCE's supply costs. MRW additionally forecast the cost of PG&E's existing resource portfolio, adding in market purchases only when necessary to meet projected demand. MRW assumed that near-term changes to PG&E's generation portfolio would be driven primarily by increases to the Renewable Portfolio Standard requirement in the years leading up to 2030 and by the retirement of the Diablo Canyon nuclear units at the end of their current license periods in 2024 and 2025. More information about this forecast is provided in Appendix B.

MRW forecasts that, on average, PG&E's generation rates will increase faster than inflation through 2038, with 2038 rates more than 20% higher than today's rates when considered on a constant dollar basis (i.e., assuming zero inflation). Underlying this result are three distinct rate periods:

1. An initial period of faster rate growth from 2018 to 2022 (1% annually above inflation);
2. A period of rate decline from 2023 to 2025 (3.5% annually below inflation), primarily due to the retirement of Diablo Canyon³²; and
3. A period of steeper rate growth between 2026 and 2030 (3.5% annually above inflation), primarily due to the replacement of Diablo Canyon with more expensive resources: energy efficiency, renewable generation, and fuel-fired generation. In addition, the retirement of Diablo Canyon increases the demand in capacity with a consequent increase

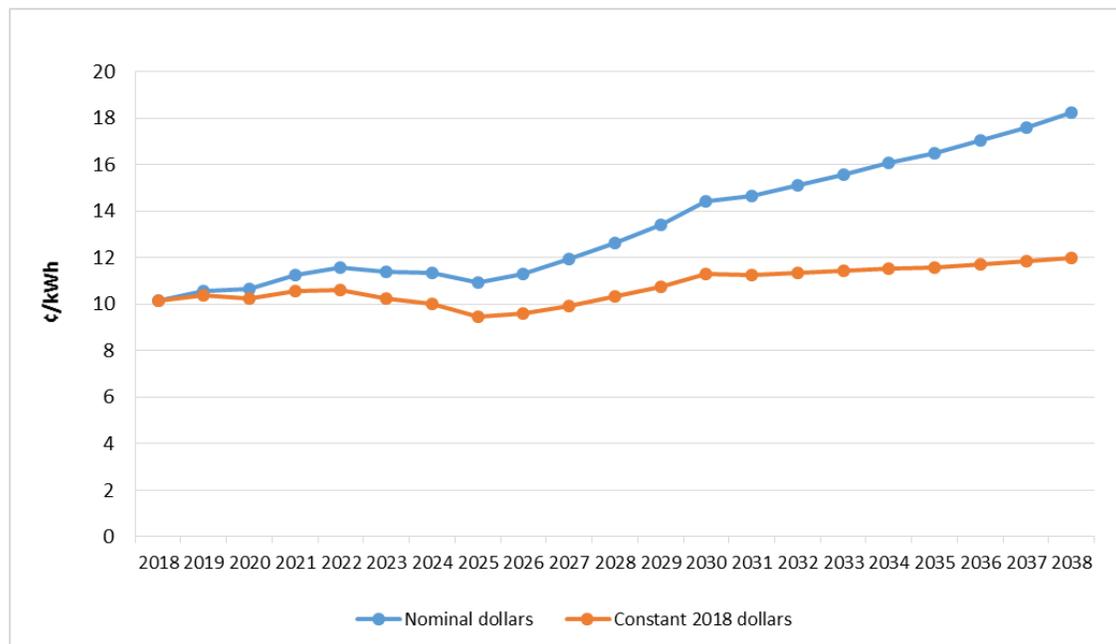
³² More information can be found in Appendix C

in capacity prices.

4. A final period of moderate rate growth through 2038 (1% annually above inflation), primarily due to the replacement of high-cost renewable power contracts currently in PG&E’s portfolio with new lower-priced contracts (reflecting the significant fall in renewable power prices in recent years).

PG&E’s bundled generation rates in each year of MRW’s forecast are shown in Figure 13, on both a nominal and constant-dollar basis.

Figure 13: PG&E Bundled Generation Rates, nominal and constant-dollar forecasts



PG&E Exit Fee Forecast

In addition to the bundled rate forecast, MRW developed a forecast of the Power Charge Indifference Adjustment (“PCIA”), which is a PG&E exit fee that is charged to CCE customers. The PCIA is intended to pay for the above-market costs of PG&E generation resources that were acquired, or which PG&E committed to acquire, prior to the customer’s departure to CCE. The total cost of these resources is compared to a market-based price benchmark to calculate the “stranded costs” associated with these resources, and CCE customers are charged what is determined to be their fair share of the stranded costs through the PCIA.

MRW forecasted the PCIA charge by modeling expected changes to PCIA-eligible resources and to the market-based price benchmark through 2038, using assumptions consistent with those used in the PG&E rate model. Based on our modelling, we expect the PCIA to decline in most years until it drops off completely around 2034. MRW’s forecast of the residential PCIA charge through 2038 is summarized in Table 6.

Table 6. PG&E Residential PCIA Charges

	2018	2019	2020	2025	2030	2035	2038
¢/kWh	2.4	1.9	2.3	1.3	0.5	0.0	0.0

In its Diablo Canyon retirement application, PG&E proposed an additional exit fee, dubbed the “Clean Energy Charge” (CEC) which CCE customers would pay to offset some of the incremental costs PG&E would incur for developing its greener portfolio. This proposal was later withdrawn. Furthermore, no party participating in the proceeding supported this charge. Because of the lack of support for the “CEC,” and the fact that PG&E’s application would have allowed CCEs to get out of the charge by procuring renewable power above and beyond the RPS requirement, we do not quantify or include this hypothetical charge in the analysis.

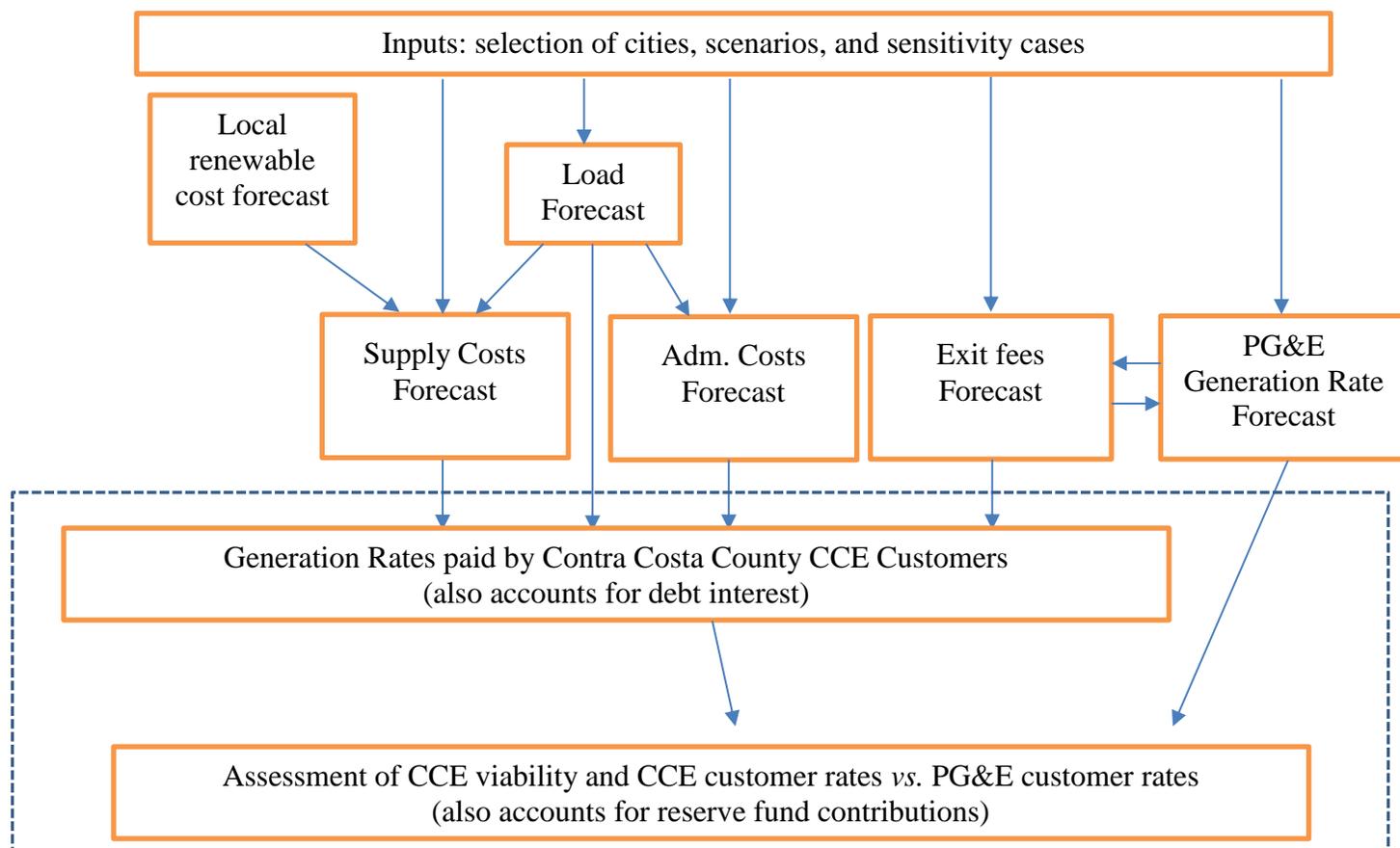
Pro Forma Elements and CCE Costs of Service

MRW conducted a pro forma analysis to evaluate the expected financial performance of the CCE and the CCE’s competitive position *vis a vis* PG&E. The analysis was conducted on a forward-looking basis from the expected start of CCE operations in 2018 through the year 2038, with several cases considered to address uncertainty in future circumstances.

Pro Forma Elements

Figure 14 provides a schematic of the pro forma analysis, outlining the input elements of the analysis and the output results. The analysis involves a comparison between the generation-related costs that would be paid by Contra Costa County CCE customers and the generation-related costs that would be paid by PG&E bundled service customers. Costs paid by CCE customers include all CCE-related costs (i.e., supply portfolio costs and administrative and general costs) and exit fee payments that CCE customers will be required to make to PG&E.

As discussed in previous sections, supply portfolio costs are informed and affected by CCE loads, by the requirements the CCE will need to meet (or will choose to meet) such as with respect to renewable procurement, and by CCE participation levels, which can vary depending on whether or not all cities in the County choose to join the CCE. Administrative and general costs are discussed further below.

Figure 14. Pro forma Analysis

Startup Costs

Table 7 shows the estimated CCE startup costs. They are based on the experience of existing CCEs as well as other CCE technical and feasibility assessments. Working capital is set to equal one hundred days of CCE revenue³³, or approximately \$22 million. This amount would cover the timing lag between when invoices for power purchases (and other account payables) must be remitted and when income is received from the customers. Initially, the working capital is provided to the CCE on credit from a bank. Typical power purchase contracts require payment for the prior month's purchases by the 20th of the current month. Customers' payments are typically received 60 to 90 days from when the power is delivered.

These startup costs are assumed to be financed over 5 years at 5% interest.

³³ The working capital has been calculated in base to Scenario 1.

Table 7. Estimated Start-Up Costs

Item	Cost
Technical Study	\$200,000
JPA Formation/Development	\$100,000
Implementation Plan Development	\$50,000
Power Supplier Solicitation & Contracting	\$75,000
Staffing	\$700,000
Consultants and Legal Counsel	\$400,000
Marketing & Communications	\$250,000
PG&E Service Fees	\$75,000
CCA Bond	\$100,000
Miscellaneous	\$300,000
Total	\$2,250,000
Working Capital	\$21,500,000
Total	\$23,750,000

Administrative and General Cost Inputs

Administrative and general costs cover the everyday operations of the CCE, including costs for billing, data management, customer service, employee salaries, contractor payments, and fees paid to PG&E. MRW conducted a survey of the financial reports of existing CCEs to develop estimates of the costs that would be faced by a Contra Costa County CCE. Administrative and general costs are phased in from 2018 to 2020, as the CCE operations expand to cover the entire territory of the County; after that, costs are escalated by 2% each year to account for the effects of inflation.

Administrative and general costs are unchanged under the three renewable level scenarios, but do vary based on how many cities join the CCE and the number of participating customer accounts. As previously mentioned, a 15% opt-out rate has been assumed for customer participation.

Cost of Service Analysis and Reserve Fund

To determine annual CCE costs and the rates that would need to be charged to CCE customers to cover these costs, MRW summed the two categories of CCE costs (i.e., supply portfolio costs, and administrative and general costs) and added in debt financing to cover start-up costs and initial working capital. Financing was assumed to be for a five-year period at an interest rate of 5%. These costs were divided by projected CCE loads to develop the average rate the CCE would need to charge customers to cover its costs (“minimum CCE rate”).

To establish the Contra Costa County CCE rate, MRW adjusted the minimum CCE rate, if needed, based on the competitive position of the CCE. In particular, when the total CCE

customer rate (i.e., the minimum CCE rate plus the PG&E exit fee) was below the projected PG&E generation rate,³⁴ MRW increased the minimum CCE rate up to the amount needed to meet the reserve refund targets while still maintaining a discount. MRW used the surplus CCE revenue from these rate increases (“Reserve Fund”) in order to maintain Contra Costa County CCE competitiveness with PG&E rates in years in which total CCE customer rates would otherwise be higher than PG&E generation rates.³⁵

³⁴ For this analysis, MRW used the average of the projected PG&E generation rates across all rate classes, weighted by the projected Contra Costa County CCE load in each rate class.

³⁵ MRW applied a Reserve Fund cap of 15% of the annual operating cost. After this cap was reached, no further rate increases were applied for the purpose of Reserve Fund contributions.

Chapter 3: Cost and Benefit Analysis

As described in the prior chapter, as part of the pro forma analysis, MRW calculated Contra Costa County CCE rates that would, where feasible, cover CCE costs and maintain long-term competitiveness with PG&E. This chapter uses those rates to compare the costs and benefits of the Contra Costa County CCE across four scenarios: (1) Minimum RPS Compliance, (2) Accelerated RPS, (3) Minimum RPS Compliance plus Local Procurement, and (4) Accelerated RPS plus Local Procurement. Costs and benefits are evaluated by comparing total CCE customer rates (including PG&E exit fees) to PG&E generation.

Scenario 1 (Minimum RPS Compliance)

Under Scenario 1, the Contra Costa County CCE meets all RPS requirements (including California State Senate Bill 350 and Diablo Canyon retirement proposal requirements), and 35% of the total load over the 20-year period is met through large hydroelectricity.³⁶

CCE Average Costs

Figure 15 summarizes the results of this scenario. The vertical bars represent the total Contra Costa County CCE customer rate and the green line represents a comparable PG&E generation rate.³⁷ Non-renewable generation (including large hydroelectric) is responsible for the bulk of the CCE's costs. Renewable generation costs will continue to increase throughout the forecast period due to the increasing RPS standards. Regarding customer costs, the PCIA exit fee is expected to decrease after 2020. Finally, the GHG allowance purchases represent a small portion of the total costs because 60% of the non-renewable generation is met by hydroelectricity. This non-carbon emitting resource therefore limits the need to purchase GHG allowances.

Note that this figure and the analogous ones to follow do not account for contributions to a rate reserve fund or other potential CCE activities such as energy efficiency or other community programs.

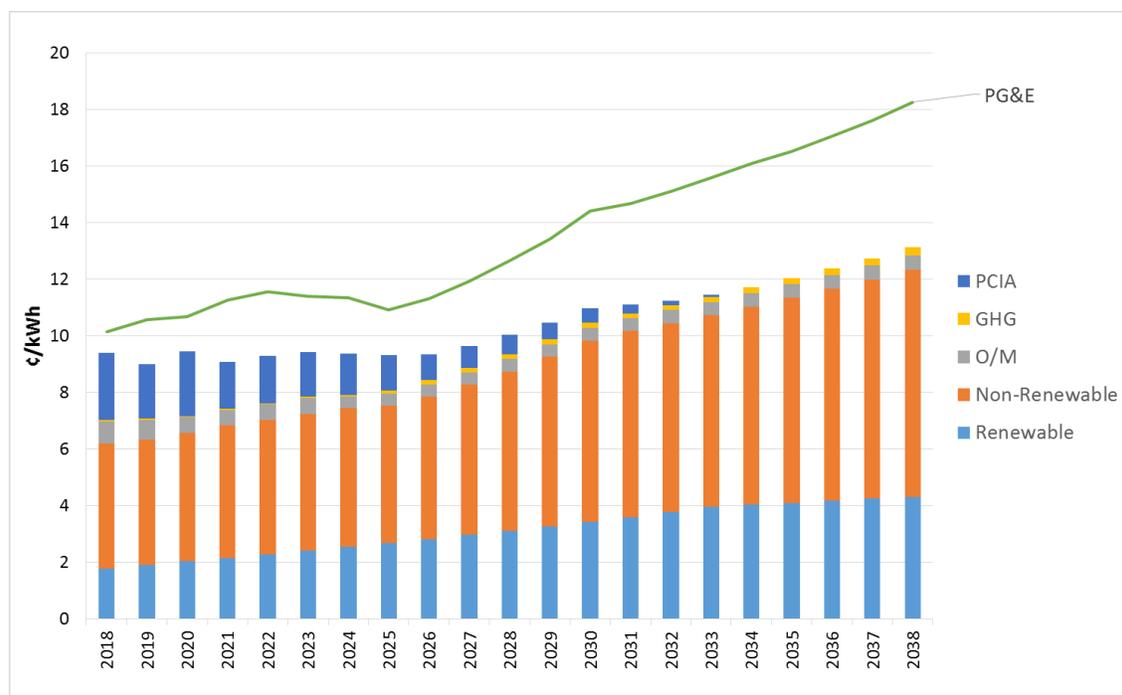
Under Scenario 1, the differential between PG&E generation rates and Contra Costa County CCE customer rates is positive in each year (i.e., CCE rates are lower than PG&E rates). As a result, Contra Costa County CCE customers' average generation rates (including contributions to the reserve fund) can be set at a level that is lower than PG&E's average customer generation rate in each year. The annual differential between the PG&E rate and the total CCE customer rate is expected to vary significantly over the course of this period (Figure 15). During the initial period from 2018-2022, the differential between the two rates increases (i.e., the CCE becomes more cost-competitive) as PG&E's rates rise, and the exit fees charged to Contra Costa County CCE customers fall as PG&E-owned gas plants expire from PCIA eligibility. Beginning in 2024, the rate differential narrows due to a decrease in PG&E generation rates stemming from the closure of the Diablo Canyon nuclear plant. After 2026, the difference between the two rates is

³⁶ 60% of the non-RPS generation in average for 2018-2038.

³⁷ All rates are in nominal dollars.

expected to increase as PG&E’s generation rates continue to increase and exit fees decline with the expiration of additional resources from PCIA eligibility.

Figure 15. Scenario 1 Forecast Average CCE Cost and PG&E Rates, 2018-2038³⁸



Residential Bill Impacts

Table 8 shows the average annual savings for residential customers under Scenario 1. The average annual bill for the residential customer on the Contra Costa County CCE program will be on average 8% lower than the same bill on PG&E rates. Note that these rate impacts assume that a rate stabilization reserve is funded during the first few years of the CCE’s existence.

Table 8. Scenario 1 Savings for Residential CCE Customers

Residential	Monthly Consumption (kWh)	Bill with PG&E (\$)	Bill with Contra Costa County CCA (\$)	Savings (\$)	Savings (%)
2018	500	121	121	0	0%
2020	500	129	124	5	4%
2030	500	189	171	18	10%
2038	500	254	227	27	11%

³⁸ This chart does not include the reserve fund.

Greenhouse Gas Emissions

Under Scenario 1, we model the Contra Costa County CCE to be 50% below PG&E's GHG emission rate. It can meet this goal by using large hydroelectric power to meet 35% of its resource needs (60% of the non-RPS load). Though this large hydro power would not qualify for RPS requirements, it is nevertheless a non-carbon emitting resource.

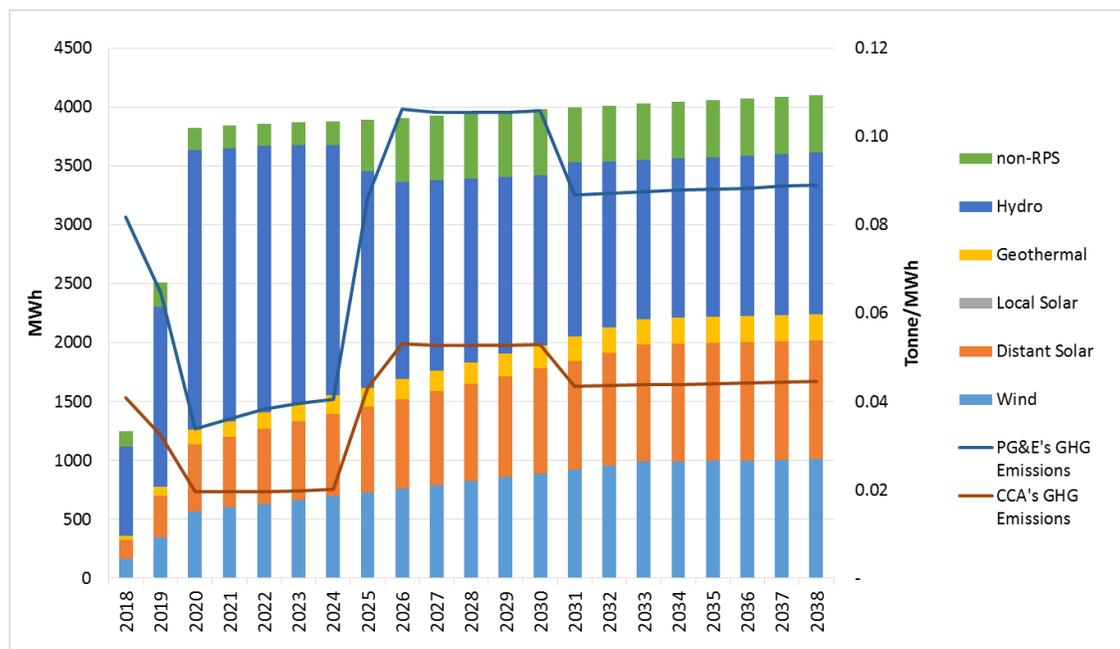
Figure 16 shows the Contra Costa CCE's generation portfolio mix (vertical bars) and GHG emissions rate (brown line) under Scenario 1, along with PG&E's GHG emissions rate for comparison (blue line). Additional GHG savings can occur if additional renewables are added to the portfolio (see Scenarios 2 and 4) or if a greater fraction of GHG-free resources (like large hydro) is used.

PG&E GHG emissions are relatively low due to the diversity in PG&E's electric mix. In addition to renewable generation, over 40% of PG&E's supply portfolio is made up of nuclear and large hydroelectric generation, both of which are considered GHG-free generation technologies. PG&E's GHG emissions rate is expected to fall between 2018 and 2020 due to increases in RPS procurement. In 2025, the retirement of the Diablo Canyon nuclear generation plant is expected to more than double PG&E's GHG emission rate as the utility increases its gas-fired generation to make up for a share of the loss.³⁹ In the following years PG&E's GHG emissions are expected to decrease as PG&E ramps up renewable procurement to meet its mandated RPS goals and the additional RPS procurement required under the Diablo Canyon retirement proposal.⁴⁰ In this scenario, the CCE's emissions rate is set to be approximately 50% of PG&E's in each year, subject to a 5% minimum supply from market purchases.

³⁹ Even if PG&E replaces the nuclear generation with renewable power and other GHG-free resources, as proposed, the new renewable resources will need to be balanced by flexible resources, which are likely to be at least in part provided by fossil-fueled power and which will therefore increase PG&E's GHG emissions.

⁴⁰ Starting in 2030, the required RPS increases from 50% to 55% under PG&E's proposal.

Figure 16. Scenario 1 Contra Costa County CCE Supply Portfolio (vertical bars) and GHG Emissions (lines) (“Normal” PG&E Hydro Conditions)



Scenario 2 (Accelerated RPS)

Scenario 2, from a renewable procurement perspective, is a more aggressive scenario. Under this scenario, the Contra Costa County CCE starts with 50% of its load served by renewable sources in 2018, and rapidly increases to 80% of its load served by renewable sources in 2030. In addition, between 2018 and 2038 Contra Costa County will provide an average of 20% of its supply through large hydroelectric sources⁴¹.

CCE Average Costs

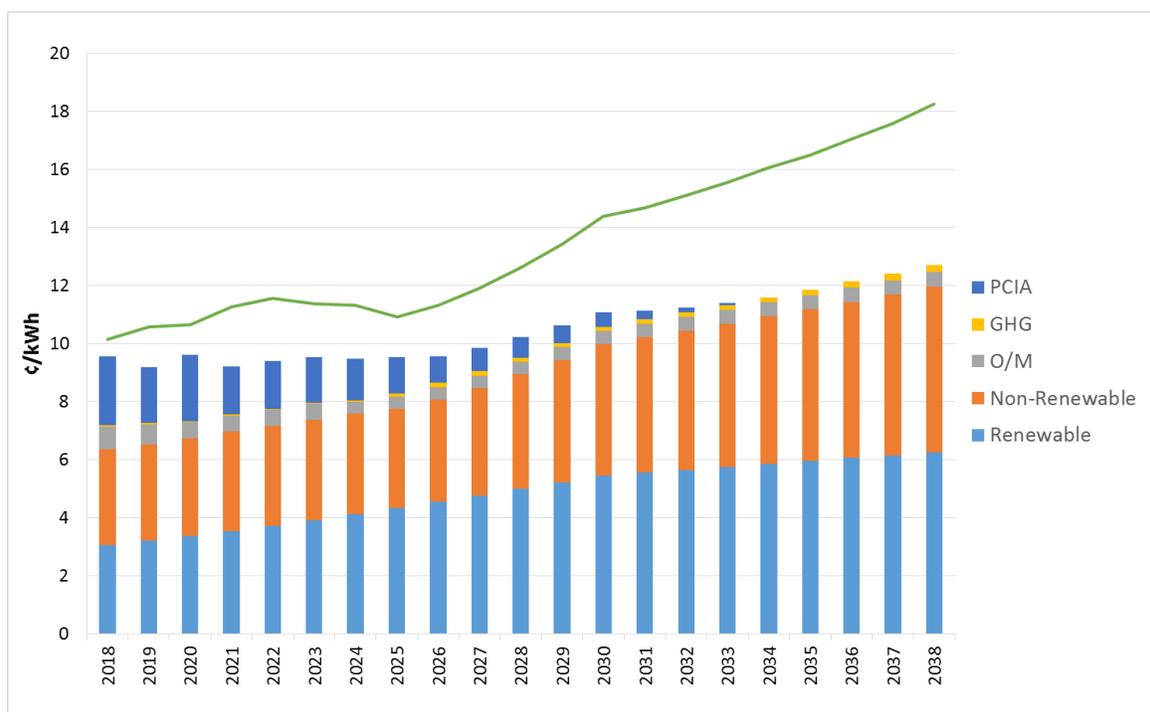
Figure 17 summarizes the results for this scenario. The vertical bars represent the Contra Costa County CCE customer rate, and the green line represents the PG&E generation rate. In this scenario, the renewable power cost is the single largest element of the CCE rate, reflecting the higher renewable content of this scenario. Non-renewable generation and the PCIA exit fee are the second and third most expensive components, respectively. As in Scenario 1, the PCIA exit fee is expected to decrease in most years beginning in 2020. Because of this scenario's larger share of GHG-free generation between 2028 and 2038, the GHG allowance purchases are an even lower portion of the total costs.

Compared to Scenario 1, Scenario 2 exhibits a lower differential between PG&E's and the CCE's customer generation rates between 2018 and 2033. After 2033, the price of renewable generation is expected to undercut the wholesale electricity market for non-RPS supplies, rendering a higher

⁴¹ 50% of the non-RPS generation for 2018-2028.

differential in Scenario 2 than in Scenario 1. With respect to PG&E's rates, this differential will continue to follow a similar pattern: positive for all years from 2018 to 2038. And as was the case in Scenario 1, Scenario 2 enables the CCE to reliably price its average generation rates lower than those of PG&E.

Figure 17. Scenario 2 Forecast Average CCE Cost and PG&E Rates, 2018-2038⁴²



Residential Bill Impacts

Table 9 summarizes the average annual savings for residential customers under Scenario 2. For the 2018-2038 period, the average annual bill for a residential customer of the Contra Costa County CCE program will be 8% lower than the same bill under PG&E rates. This is a little less than, but close to, the bill savings under Scenario 1. Note that these rate impacts assume that a rate stabilization reserve is funded during the first few years of the CCE's existence. Thus, even though a "gap" between the CCE costs and PG&E rates can be seen in Figure 17, the bill savings in 2018 is zero, as the additional CCE funds are assumed to go to the reserve rather than as a customer bill savings.

⁴² This chart does not include the reserve fund.

Table 9. Scenario 2 Savings for Residential CCE Customers

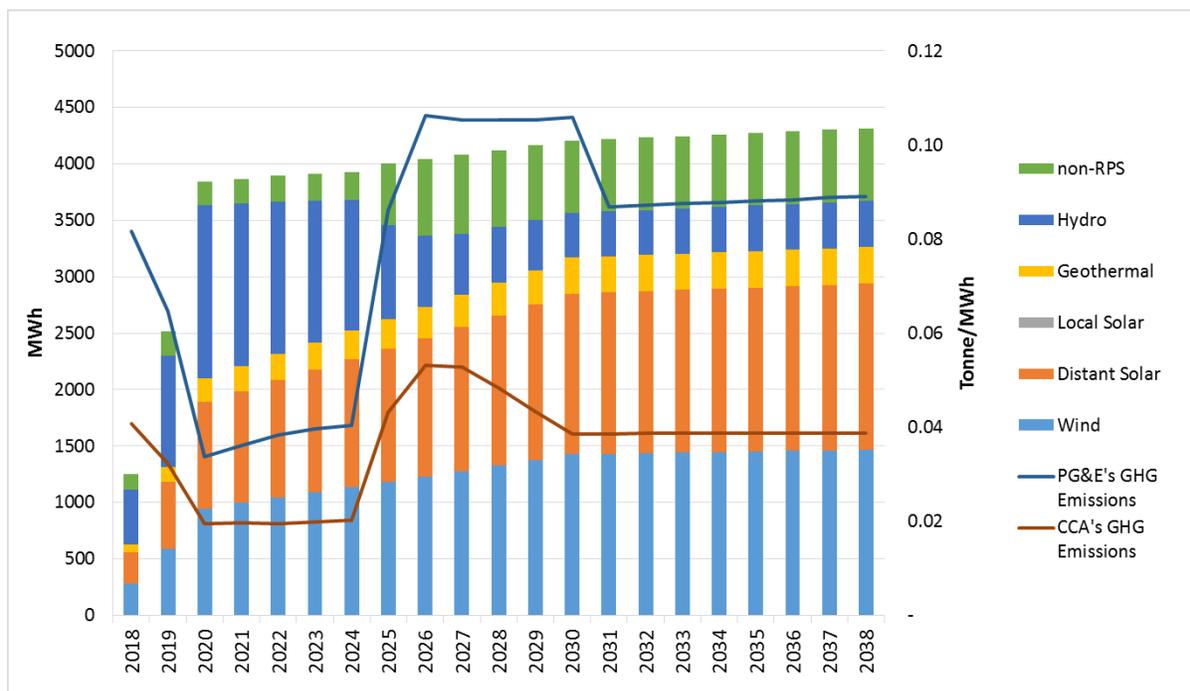
Residential	Monthly Consumption (kWh)	Bill with PG&E (\$)	Bill with Contra Costa County CCE (\$)	Savings (\$)	Savings (%)
2018	500	121	121	0	0%
2020	500	129	125	4	3%
2030	500	189	172	17	9%
2038	500	254	225	29	11%

GHG Emissions

Under Scenario 2, we model the Contra Costa County CCE to at least as much carbon-free generation as PG&E. As in Scenario 1, in years where the assumed renewables would not result in the CCE halving PG&E's GHG emissions, we add large hydroelectric generation to the CCE's resource portfolio to make up the difference, subject to a 5% minimum supply from market purchases. In other years when the CCE's RPS targets are sufficient to provide GHG savings relative to PG&E, we assume that emissions are further reduced by sourcing 50% of the non-RPS supply from large hydro. The result is a portfolio that averages 20% large hydro.

Figure 18 compares the Scenario 2 GHG emissions from 2018-2038 for the Contra Costa County CCE with what PG&E's emissions would be for the same load if no CCE were formed. Because Scenario 2 has a higher renewable generation target (80% by 2030), the hydroelectric generation necessary to achieve the same GHG emissions reduction is lower. As a result of trading off large hydro for RPS-eligible energy, GHG emissions in Scenario 2 are the same as Scenario 1 through 2027, after which the CCE's portfolio will produce less than half the GHG emissions compared to PG&E.

Figure 18. Scenario 2 Contra Costa County CCE Supply Portfolio (vertical bars) and GHG Emissions (lines) (“Normal” PG&E Hydro Conditions)



Scenario 3 (Minimum RPS Compliance plus Local Procurement)

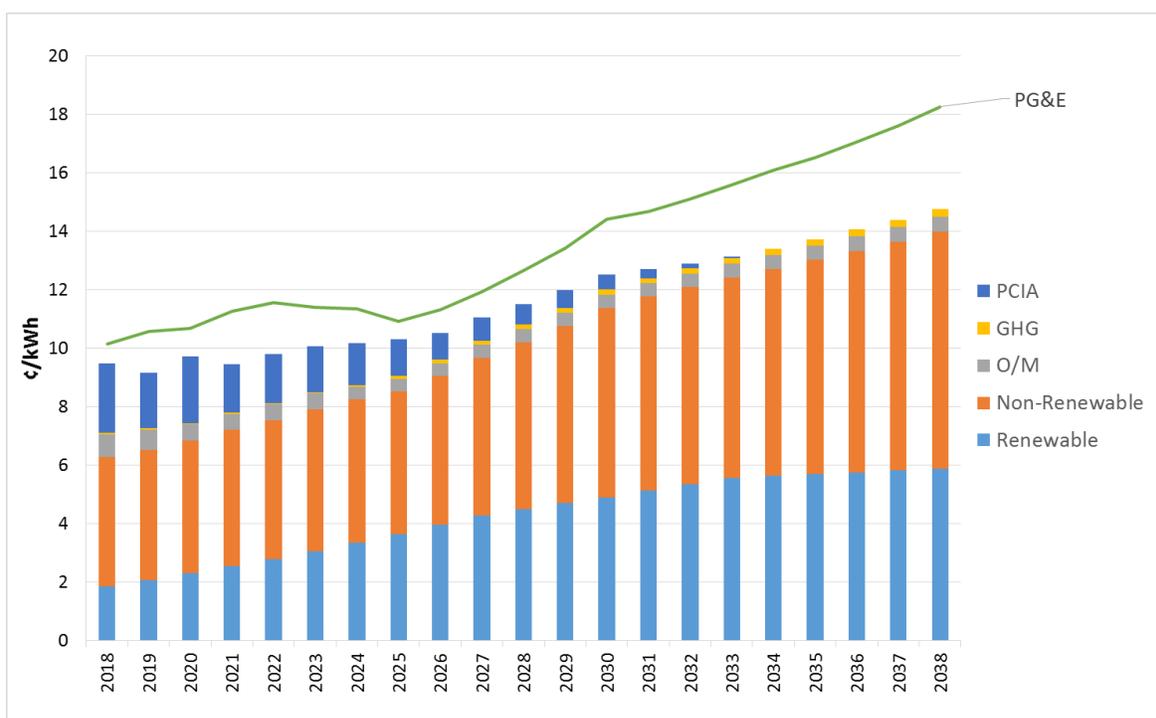
Scenario 3 is identical to Scenario 1, save for a greater portion of locally sourced renewables. Under Scenario 3, local renewables increase annually, reaching 50% of the renewable supply by 2027 and continues at 50% through 2038.

CCE Costs

Figure 19 summarizes the results for this scenario. The vertical bars represent the Contra Costa County CCE customer rate, and the green line represents the PG&E generation rate. As with Scenario 1, the non-renewable cost is the largest component of the CCE’s rates, followed by renewable generation costs. The latter are greater than in Scenario 1 due to the higher prices of local generation resources. As with previous scenarios, the PCIA exit fee is the third largest expenditure and it is expected to decrease most years after 2020. As with Scenario 1, the costs associated with GHG allowance purchases are responsible for a marginally larger percentage of the CCE's total costs between 2028 and 2038. This is mostly due to the lower share of GHG-free emissions.

The Scenario 3 differential between PG&E generation rates and Contra Costa County CCE rates falls below the differential in Scenarios 1 and 2. However, the CCE rates are expected to be lower than PG&E's generation rates for the entire forecast period, which will allow the CCE to collect reserve fund contributions annually from 2018 to 2038.

Figure 19. Scenario 3: Forecast Average CCE Cost and PG&E Rates, 2018-2038



Residential Bill Impacts

Table 10 summarizes the average residential bill impacts under Scenario 3. Between 2018 and 2038, the annual bill for a residential customer of the Contra Costa County CCE program will be, on average, 4.5% lower than a corresponding PG&E bill.

Table 10. Scenario 3 Savings for Residential CCE Customers

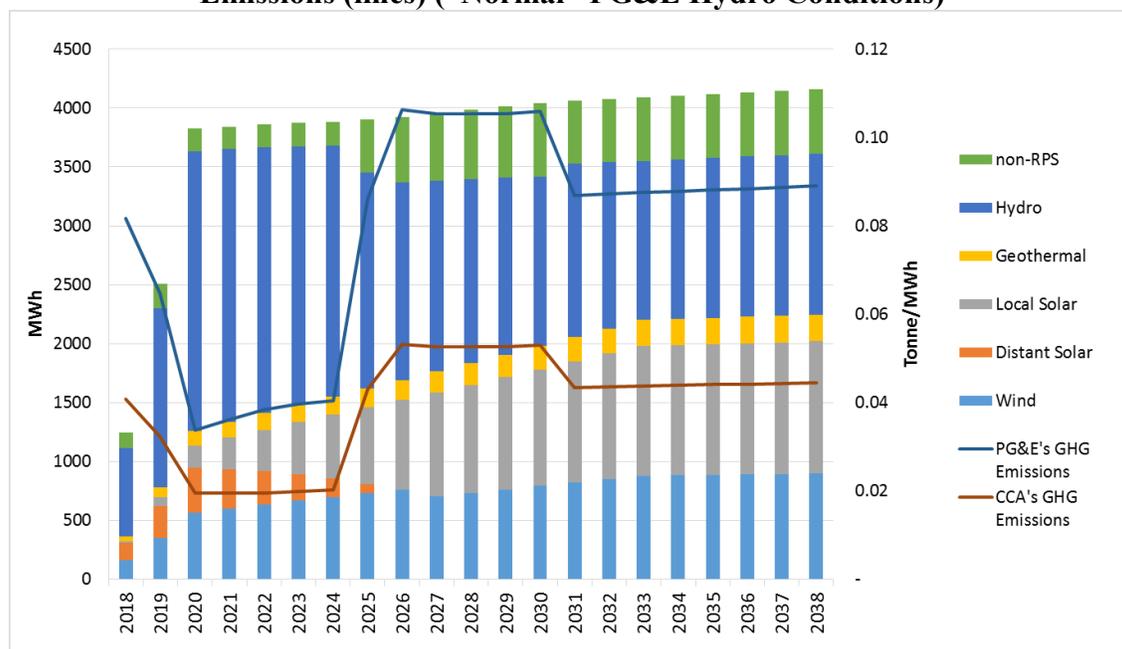
Residential	Monthly Consumption (kWh)	Bill with PG&E (\$)	Bill with Contra Costa County CCA (\$)	Savings (\$)	Savings (%)
2018	500	121	121	0	0%
2020	500	129	126	3	2%
2030	500	189	179	10	5%
2038	500	254	236	18	7%

GHG Emissions

The emissions pattern for Scenario 3 is identical to Scenario 1 due to the equal GHG-free generation proportion. The only difference is that part of this generation is provided by local sources. Figure 20 shows the GHG emissions from 2018-2038 for the Contra Costa County CCE

under Scenario 3. Note that GHG emissions from the Contra Costa CCE supply and PG&E supply are the same as in Scenario 1.

Figure 20. Scenario 3 Contra Costa County CCE Supply Portfolio (vertical bars) and GHG Emissions (lines) (“Normal” PG&E Hydro Conditions)



Scenario 4 (Accelerated RPS plus Local Procurement)

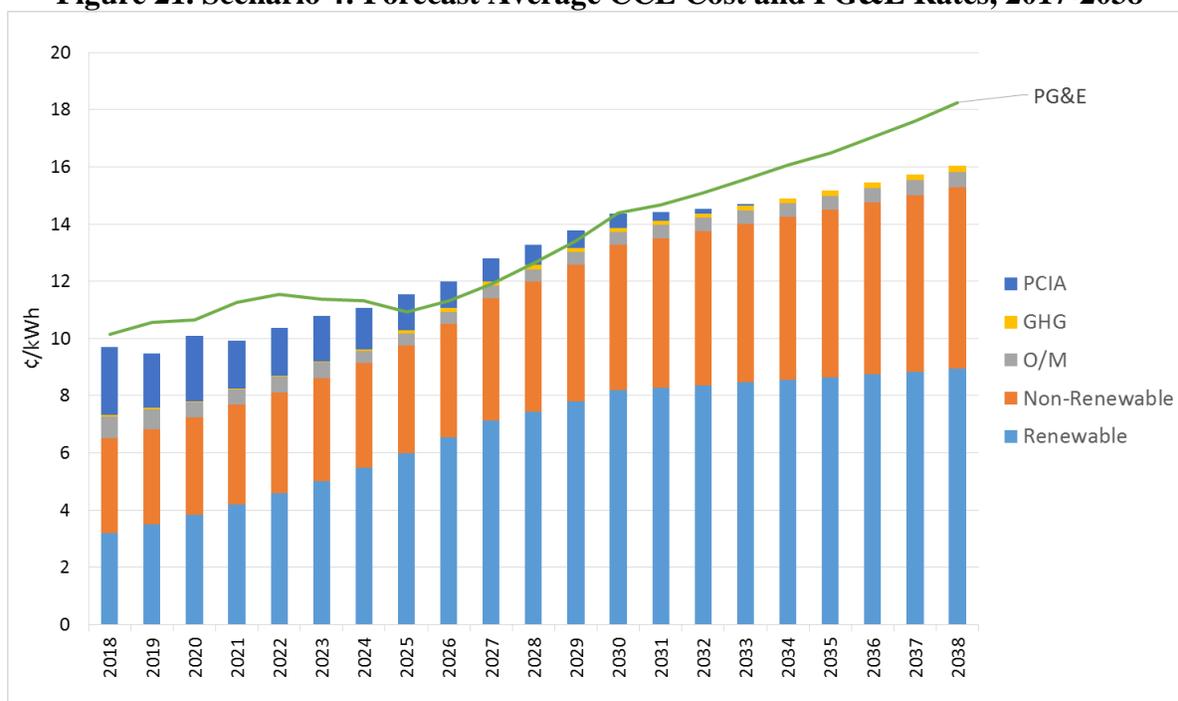
Scenario 4 is the same scenario as Scenario 2 but with a more substantial portion of the generation sourced from local renewable sources: increasing annually and achieving 50% of the total RPS supply by 2027 through 2038.

CCE Average Costs

Figure 21 summarizes the results for this scenario. The vertical bars represent the Contra Costa County CCE customer rate, and the green line represents the PG&E generation rate. Under Scenario 4, the cost for renewables forms the largest component of the CCE’s rates and grows steadily to account for nearly 60% of the total CCE rate in 2030. Non-renewable generation is the next largest cost component of the rate, followed by the PCIA exit fee, which is expected to decrease in most years beginning 2020. As with Scenario 2, the costs for GHG allowance purchases in Scenario 4 are a smaller portion of total costs because of more RPS power.

The differential between PG&E generation rates and Contra Costa County CCE customer rates from 2018 to 2038 in Scenario 4 is the lowest of the four scenarios. This is because Scenario 4 has the most expensive supply portfolio, comprised of more locally sources renewables. Similar to the other scenarios, in Scenario 4 the collection of the reserve fund contributions at the end of 2038 is positive. Contra Costa County CCE rates in Scenario 4 are forecasted to be lower than expected PG&E generation rates for all years from 2018 to 2038, except from 2025 to 2030.

Figure 21. Scenario 4: Forecast Average CCE Cost and PG&E Rates, 2017-2038



Residential Bill Impacts

Table 11 summarizes the average residential bill impacts under Scenario 4. Over the study period, the annual bill for a residential customer of the Contra Costa County CCE program will be, on average, 1% lower than the same bill under PG&E rates under Scenario 4. However, the higher local renewable costs coupled with their assumed high usage cause the CCE’s rates to exceed PG&E’s in some years. In particular, from 2025 through 2030, the total CCE rates (CCE rate plus PCIA) is projected to be higher than the PG&E generation rate. This implies that very aggressive pursuit of local renewables must be carefully weighed against their additional costs.

However, it should also be noted that the study assumed a conservative \$30/MWh adder on top of the build costs of local solar projects to account for costs of land acquisition/ opportunity costs. If a significant fraction of the local projects does not have these higher soft costs, then this higher level of local renewables can be developed at competitive rates.

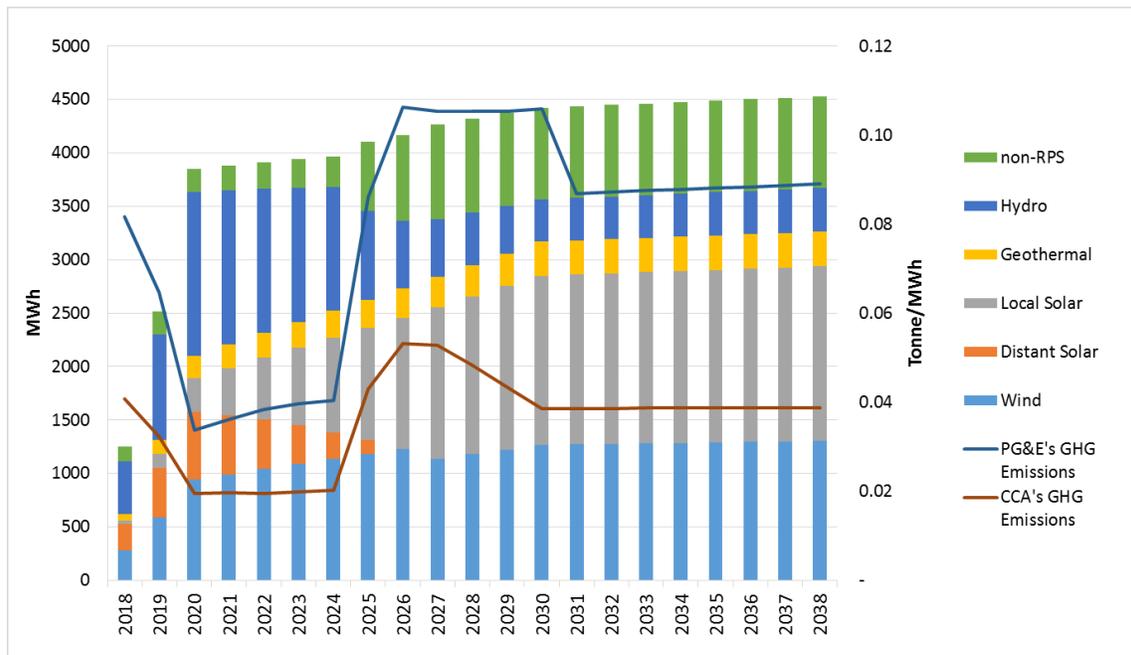
Table 11. Scenario 4 Savings for Residential CCE Customers

Residential	Monthly Consumption (kWh)	Bill with PG&E (\$)	Bill with Contra Costa County CCA (\$)	Savings (\$)	Savings (%)
2018	500	121	121	0	0%
2020	500	129	128	1	0.7%
2030	500	189	199	-10	-5%
2038	500	254	242	12	5%

GHG Emissions

The GHG emissions pattern for Scenario 4 is the same as Scenario 2 due to the scenarios having the same shares of GHG-free generation; the only difference being that local solar generation is assumed to replace solar supplies from more distant locations. Figure 22 compares the GHG emissions from 2018-2038 for the Contra Costa County CCE under Scenario 4 with what PG&E’s emissions would be for the same load were no CCE formed.

Figure 22. Scenario 4 Contra Costa County CCE Supply Portfolio (vertical bars) and GHG Emissions (lines) (“Normal” PG&E Hydro Conditions)



Chapter 4: Sensitivity of Results to Key Inputs

In addition to the base case forecast described above, MRW has assessed alternative cases to evaluate the sensitivity of the results to possible conditions that would have an impact on Contra Costa County CCE's technical study. The metric considered to compare the alternative sensitivity cases to the base case is the differential between the annual average generation rates for PG&E bundled customers and for Contra Costa County CCE customers over the first ten years (2018-2028).⁴³ The latter 10 years were not included as they are both uncertain and skew the average results due to the widening gap between modeled PG&E's rates and the CCE's average cost.

The base-case analysis (Chapter 3 –Scenario 1) was developed as a reasonable and conservative assessment of the Contra Costa County CCE. In addition to the base case analysis, MRW analyzed alternative cases to address seven risks: (1) low participation, (2) higher local renewable power prices, (3) higher renewable power prices, (4) higher natural gas prices, (5) lower PG&E portfolio costs, (6) higher PCIA charges, and (7) a combination of these six risks (stress scenario).

Lower Participation Sensitivity

This sensitivity case evaluates the impact of lower participation on the CCE program. Lower participation could be due to a higher customer opt-out rates, or if some of the cities included in the study choose not to participate in the CCE program. If fewer customers join, CCE rates will generally be higher because about \$7 million of annual CCE costs are invariant to the amount of CCE load. In the Lower Participation sensitivity, we assume that the load for the Contra Costa County CCE is 70% of the potential load.⁴⁴ Average administration costs in this scenario are 12% higher than in the base case scenario. These higher administration costs do not have a big impact on the CCE rates because administration costs are a small part of the total CCE rate (5% on average). The impact of this sensitivity case is to reduce the 2018-2028 average rate differential by 0.07¢/kWh relative to the base case.

Table 12. Lower Participation Sensitivity Results, 2018-2028

Period 2018-2028	Average Admin costs (¢/kWh)	Average rate differential (¢/kWh)
Base	0.45	1.86
Low participation	0.51	1.79

⁴³The Contra Costa County CCE rate includes the PG&E exit fees (PCIA charges) that will be charged to CCE customers but does not include the rate adjustment for the reserve fund or other possible CCE activities.

⁴⁴ In the base case we considered 85% of the potential load.

Higher Local Renewable Power Prices Sensitivity

This sensitivity case evaluates the impact of higher local renewable power prices on the CCE's financial viability. As discussed in Appendix B, in the base case, the solar local renewable power price starts at \$98/MWh in 2018 and it increases following the price curve. In the Higher Local Renewable Power Prices sensitivity, we assume that local renewable prices would be 20% higher than the base case prices. These higher prices affect only CCE rates for Scenario 3 and Scenario 4 (Scenario 1 and Scenario 2 do not include local generation), reducing the 2018-2028 average rate differential by 0.3¢/kWh relative to the base case.

Table 13. Higher Local Renewable Power Prices Sensitivity Results, 2018-2028⁴⁵

Period 2018-2028	Average local renewable prices (\$/MWh)	Average rate differential (¢/kWh)
Scenario 3	114.30	1.14
High local renewable prices	137.20	0.85

Higher Renewable Power Prices Sensitivity

This sensitivity case evaluates the impact of higher renewable power prices on the CCE's financial viability. As discussed in Appendix B, in the base case, renewable power prices are flat in nominal dollars through 2022, based on the assumption that projected declines in renewable development costs will offset increases associated with the expected expiration of federal renewable tax credits.^{46,47} In the Higher Renewable Power Prices sensitivity, we assume that renewable prices would be flat in nominal dollars through 2022 if it were not for the tax credit expirations and add the impact of the tax credit expirations to the base case prices. Average renewable power prices in this scenario are 0-10% higher than in the base case scenario through 2021, about 20% higher in 2021 and 2022, and 30% higher after 2022 when the solar investment tax credit is reduced to 10%. These higher prices affect both the CCE and PG&E, but they have a greater effect on the CCE because PG&E has significant amounts of renewable resources under long-term contract. The impact of this sensitivity case is to reduce the 2018-2028 average rate differential by 0.35¢/kWh relative to the base case.

⁴⁵ Results for Scenario 3.

⁴⁶ The Investment Tax Credit (ITC) which is commonly used by solar developers, is scheduled to remain at its current level of 30% through 2019 and then to fall over three years to 10%, where it is to remain. The federal Production Tax Credit (PTC), which is commonly used by wind developers, is scheduled to be reduced for facilities commencing construction in 2017-2019 and eliminated for subsequent construction.

U.S. Department of Energy. Business Energy Investment Tax Credit (ITC). <http://energy.gov/savings/business-energy-investment-tax-credit-itc>; U.S. Department of Energy. Electricity Production Tax Credit (PTC). <http://energy.gov/savings/renewable-electricity-production-tax-credit-ptc>

⁴⁷ The base case forecast would also be consistent with a scenario in which the tax credit expirations are delayed.

Table 14. Higher Renewable Power Prices Sensitivity Results, 2018-2028

	Average RPS prices (\$/MWh)	Resulting average rate differential (¢/kWh)
Base	53.2	1.86
High renewable prices	65.1	1.51

Higher Exit Fee (PCIA) Sensitivity

PG&E's PCIA exit fees are subject to considerable uncertainty. Under the current methodology, PCIA rates can swing dramatically from one year to the next, and this methodology is currently under review and may be adjusted in the coming years. MRW therefore evaluated a stress case in which PCIA rates do not fall after 2018, as anticipated in the base case, but instead remain at 2018 levels through 2028. This increases the 2028 PCIA by more than 300% of its base case value. The impact of this sensitivity case is to reduce the 2018-2028 average rate differential by 0.86¢/kWh relative to the base case.

Table 15. Higher PCIA Exit Fee Sensitivity Results, 2018-2028

	Average PCIA prices (¢/kWh)	Resulting average rate differential (¢/kWh)
Base	1.5	1.86
High PCIA	2.4	1.00

Lower PG&E Portfolio Cost Sensitivity

While changes to natural gas prices and renewable power prices affect both the CCE and PG&E, dampening the impact on the CCE's cost competitiveness, reductions to the costs to operate and maintain PG&E's nuclear and hydroelectric facilities would provide cost savings to PG&E that would not be offset by cost savings to the CCE. MRW considered a case in which PG&E's overall generation rates are 10% below the base case, driven by reductions to PG&E's nuclear and hydroelectric portfolio costs. Under such a scenario, the 2018-2028 average rate differential would be reduced by 1.12¢/kWh relative to the base case scenario.

Table 16. Lower PG&E Portfolio Sensitivity Results, 2018-2038

	Average PG&E Rate (¢/kWh)	Resulting average rate differential (¢/kWh)
Base	11.2	1.86
Low PG&E portfolio costs	10.1	0.74

Higher Natural Gas Prices Sensitivity

Natural gas prices have been low and relatively steady over the last few years, but they have historically been quite volatile and subject to significant swings from local supply disruptions (e.g., Hurricanes Katrina and Rita in 2005). MRW analyzed a gas price sensitivity case using the U.S. Energy Information Administration’s High Scenario natural gas prices forecast,⁴⁸ which is on average 50% higher than MRW’s base case forecast for the period 2018-2028. Natural gas price increases affect power supply costs for both a Contra Costa County CCE and PG&E; however, the nuclear and hydroelectric capacity in PG&E’s resource mix makes PG&E less sensitive than a Contra Costa County CCE to changes in natural gas prices. The net effect of higher natural gas prices is therefore to increase CCE rates relative to PG&E rates⁴⁹ (i.e., reduce the average rate differential). Under the sensitivity conditions considered, the 2018-2038 average rate differential decreases relative to the base case by 1.68¢/kWh.

Table 17. Higher Natural Gas Prices Sensitivity Results, 2018-2028

	Average PG&E Rate (¢/kWh)	Resulting average rate differential (¢/kWh)
Base	11.2	1.86
Low PG&E portfolio costs	10.1	0.18

Stress Case and Sensitivity Comparisons

All rate differentials (i.e., the CCE’s competitive positions) are lower in the sensitivity cases than in the base case scenario for all years from 2018 to 2028 (**Table 18**). To evaluate a more extreme scenario, MRW developed a stress case that combines all the sensitivity cases: (1) low

⁴⁸ U.S. Energy Information Administration. “2015 Annual Energy Outlook,” Table 13

⁴⁹ For Scenarios 2 and 4 the high gas natural prices case has less negative impact due to the high proportion of renewable generation.

participation, (2) higher local renewable power prices, (3) higher renewable power prices, (4) higher natural gas prices, (5) lower PG&E portfolio costs, and (6) higher PCIA charges. The 2018-2028 average rate differential for this stress case is negative, at -4.08¢/kWh, meaning that CCE customer costs would exceed PG&E customer costs under this scenario.

Table 18. Stress Test Results, 2018-2028

	Resulting average rate differential (¢/kWh)
Base	1.86
Stress Scenario	-2.3

Figure 23. Difference Between PG&E Customer Rates and CCE Customer Rates Under Each Sensitivity Case, 2018-2028⁵⁰

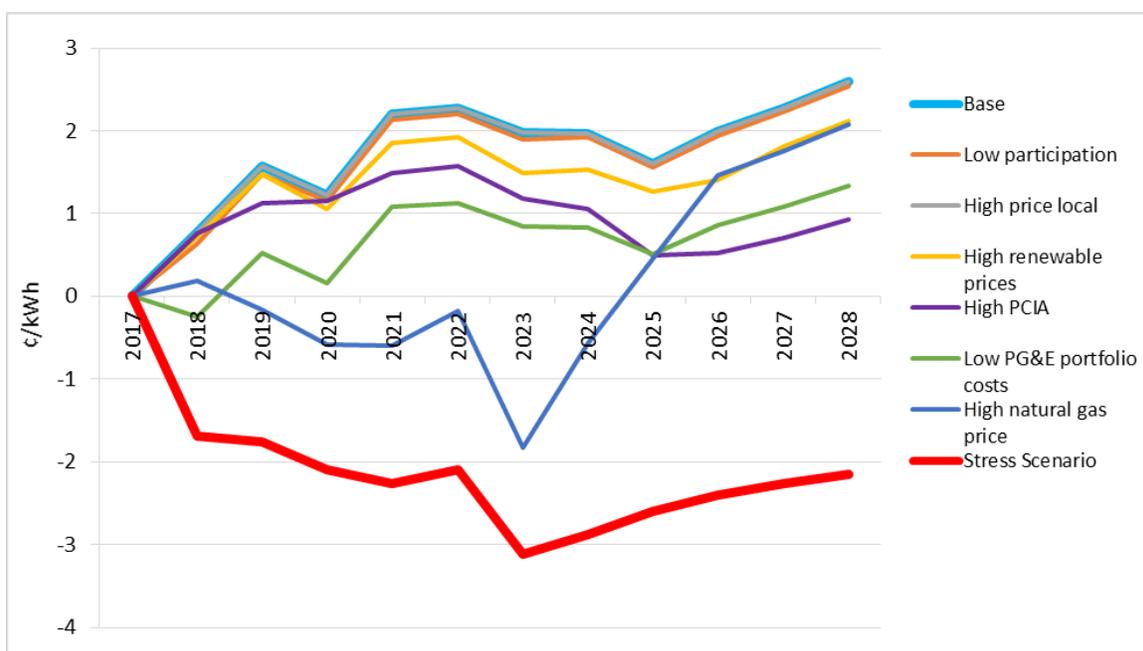


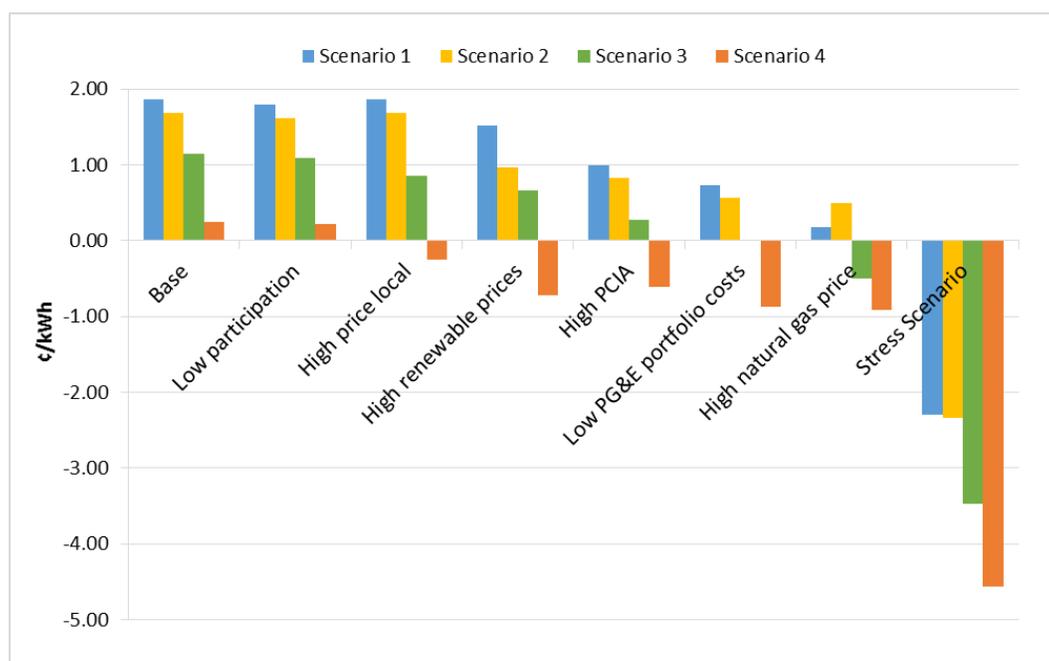
Figure 23 shows the difference between the PG&E customer rates and the Contra Costa County CCE customer rates (including exit fees) in the base case, and in each of the sensitivity scenarios, for each year from 2018 to 2028. As Figure 23 illustrates, CCE customer rates are lower than PG&E customer rates in each of the individual sensitivity cases in each year. For the High Natural Gas Price sensitivity case, in 2023 the rate differential drops due to an increase on the

⁵⁰ The chart plots the sensitivity cases for Scenario 1, therefore it does not reflect the effect of the High Price Local sensitivity (it only applies to Scenario 3 and 4).

PCIA, as the PCIA is highly sensitive to the natural gas prices. Under the Stress Scenario case, the rate differential is negative for each year (i.e., CCE rates are higher than PG&E generation rates).

The results shown above reflect the Minimum RPS Compliance supply scenario (Scenario 1). MRW additionally evaluated each sensitivity scenario under the four alternative supply scenarios: (1) Minimum RPS Compliance, (2) Accelerated RPS, (3) Minimum RPS Compliance plus Local Procurement, and (4) Accelerated RPS plus Local Procurement. Figure 24 depicts the average rate differentials for 2018-2028 for each sensitivity case under the four supply scenarios.

Figure 24. Difference Between PG&E Customer Rates and CCE Customer Rates Under Each Sensitivity Case and Supply Scenario, 2018-2028 Average



Looking at 2018-2028, Scenario 1 (Minimum RPS Compliance) is the least costly scenario for the CCE, and therefore has the best rate differential under most of the sensitivity cases considered.⁵¹ Scenario 2 (Accelerated RPS), though still quite competitive with PG&E, fares slightly worse, with a rate differential approximately 10-20% lower than in Scenario 1 for most of the sensitivity cases considered. The one exception is the High Natural Gas Price sensitivity case, in which Scenario 1 has worse results than Scenario 2. This is due to the higher gas-fired generation content in Scenario 1, which makes the supply portfolio more susceptible to volatility in natural gas prices than Scenario 2. For most of the sensitivity cases, rate differentials for

⁵¹ This is only looking at the period 2018-2028. From 2028-2033 the rates show the same pattern between the four scenarios. If we consider the period 2033-2038, Scenario 2 would be the least costly scenario. After 2033 the prices of renewable generation are expected to be lower than the wholesale electric market, which makes Scenario 2 less costly than Scenario 1 in the period 2033-2038.

Scenario 3 are lower than Scenario 1 and Scenario 2. Scenario 4 is the costliest scenario, with rate differentials much lower than the other three scenarios.

In the stress case, Contra Costa County CCE customer rates exceed PG&E customer rates on average over the 2018-2028 period for all four scenarios, with the negative rate differential being highest in Scenario 4 at -4.5¢/kWh.

Conclusions

Under Scenarios 1, 2 and 3, Contra Costa County CCE customer rates compare favorably to PG&E rates in all years from 2018 to 2038. As modeled, in Scenario 4 Contra Costa County CCE customer rates would be higher than PG&E rates from about 2025 and 2030. Under Scenarios 1 and 2 (simple RPS compliance), Contra Costa County CCE customer rates remain below PG&E rates under all but the most extreme sensitivity case considered. Scenario 3 rates could meet or beat PG&E's under all but the high natural gas and stress cases. Under the stress case, irrespective of the supply scenario considered, CCE rates are higher than PG&E rates. While the stress case may appear extreme given that it involves seven adverse sensitivities simultaneously occurring, cost volatility in the power industry is well established, and the possibility of adverse conditions arising in an isolated year should be understood and planned for in any CCE venture.

Chapter 5: Macroeconomic Impacts

This chapter discusses the job impacts within Contra Costa County for each of the four scenarios. All four scenarios modeled showed positive economic and job impacts. The mix and amount of jobs created would depend upon policy decisions made by the CCE board, primarily trading off the economic stimulus from lower electricity bills versus the direct jobs created by local (higher cost) renewable energy projects sponsored by the CCE.

To understand just how job impacts can come about, and the extent of those changes (positive or negative), a brief description of elements associated with the CCE and how they influence the existing economy is provided.

How a CCE interacts with the Surrounding Economy

The establishment and operation of a CCE creates a new set of spending elements (also referred to as “demands”) as a community changes the type of electricity generation they want to purchase, where the new mix of generation is to be located, adjustments necessary for existing generating assets of the provider utility, and implications on customers’ bills because of retail rate differentials. Some of these new elements have temporary effects, while others have long-term effects. Investment in locally sited solar will result in temporary direct creation of jobs whereas subsequent *maintenance* will support some on-going direct jobs. Regardless of the duration, when a direct job is created in a sector, there will be a multiplier response on “backwardly-linked” jobs with supplier businesses if the supplier is present in the economy. The new elements include:

- **Administration** – direct jobs, long-term effect. County staffing, professional-technical services and I/T-database services
- **Net Rate Savings (or bill savings)** – long-term effect. County households have an increase in their spending ability, County commercial and industrial energy customers experience a reduction in their costs-of-doing business which makes them each more competitive, garnering more business that requires more employees, and municipal energy customers can provide more local services which require more local government staff.
- **New Renewable Capacity Investment within County & Surrounding counties** – direct jobs, short-term, two of the four scenarios.
- **New Renewable Operations within County & Surrounding counties** – direct jobs, long-term, two of the four scenarios.
- **Net Generating Capacity and Operations offsets for PG&E outside of county** – direct jobs, short and long-term, none because we are not focused on the *rest of California* economy.

To frame expectations around how many direct jobs can be created in the County from the above CCE elements, consideration must be given to (a) how much of the spending associated with the CCE scenario is fulfilled by a within-county business or resident workforce, and (b) what do these locally-fulfilled dollars represent in terms of current annual County business activity (e.g., is this a large spending event?).

Job Impacts of Proposed CCE Scenarios

We examine each of the four scenarios for their influence on the County economy and the economy of the four surrounding counties combined (a ring region comprised of Alameda, Sacramento, San Joaquin, and Solano counties). The basis for including the surrounding counties is (i) interdependence of the economies in terms of business-to-business transactions (in part due to proximity) and labor commuting flows (both in and out), as well as (ii) the siting of 50 percent of the proposed CCE funded small-scale solar projects beyond Contra Costa County. The scenario structures assume no electric customer participation from beyond Contra Costa County therefore the proposed *bill savings* are allocated across customer segments solely within Contra Costa County.

The possible sources of *initial* job change in any of the scenarios include:

- CCE Administration *spending* 2018 to 2038 (within Contra Costa County)
- Bill Savings *less* Customer's expense for on-site solar deployed 2018 to 2038 (within Contra Costa County)
- Investment in small-scale Solar 2018 to 2030 (Contra Costa and the 4-county ring region)
- O&M spending on small-scale Solar 2018 to 2038 (Contra Costa and the 4-county ring region)

Only scenarios 3 and 4 include investment for small-solar projects in Contra Costa County and the surrounding region of counties. Once each regional economy experiences its initial change related to any of the above scenario elements, a macroeconomic forecasting tool (the REMI model⁵²) captures impacts from inter-regional transactions (of commuters, of business sales), and impacts from changes in Contra Costa County's relative *cost-of-living* and *cost-of-doing business* resulting from bill savings, and impacts associated with *multiplier effects*.

Overview of Scenario Effects

It is helpful to understand how the various scenarios “stack up” in terms of the four sources that will exert an influence on the local economies. Table 19 presents the cumulative (2018 to 2038) stimuli - bill savings, administrative spending, and where relevant, demands related to investment, O&M. The amounts are a roll-up of nominal values. Scenario 1 poses the greatest amount of Rate Savings for County CCE customers (\$2,390 million), and Scenario 4 poses the largest amount of solar investment *demand* (\$827 million) for in-county installations. Ensuing O&M spending (Scenarios 3 and 4) will increase as the investment *demand* increases. None of the displaced renewable capacity by PG&E (investments under the “business-as-usual” or “without CCE” case) occurs in either Contra Costa or the surrounding 4 counties.

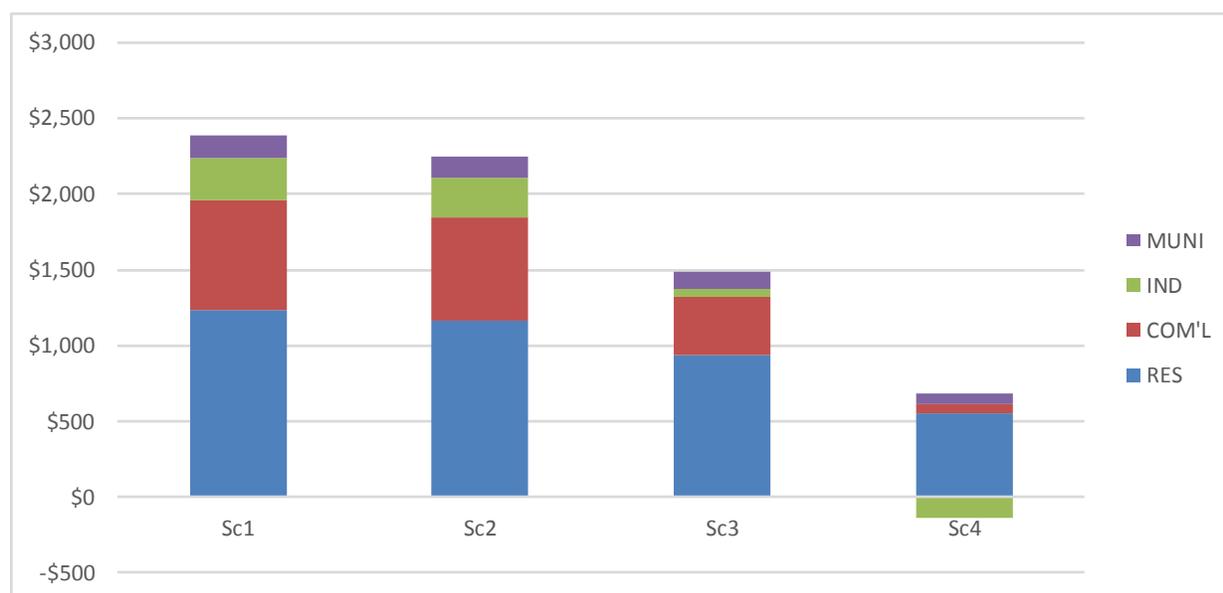
⁵² Regional Economic Models, Inc. of Amherst, MA. www.remi.com

Table 19. CCE Scenario Economic Characteristics (2018-2038, Millions of nominal dollars)⁵³

Scen.	Net Rate savings County customers	CCE Small Solar Investment		CCE Small Solar O&M	
		Contra Costa County	Neighboring Counties	Contra Costa County	Neighboring Counties
1	\$2,390	\$0	\$0	\$0	\$0
2	\$2,251	\$0	\$0	\$0	\$0
3	\$1,485	\$456	\$456	\$234	\$234
4	\$542	\$827	\$827	\$375	\$375

Figure 25 presents the estimated *net* rate savings for various customer-segments in the County by CCE scenario. The rate savings benefit accrues foremost to the residential segment, followed by the commercial segment. The municipal segment has fairly constant rate savings regardless of scenario. In addition to the magnitude of overall net rate savings and local solar-related business opportunities, this segment distribution across customer segments influences part of the job impact response (amidst solar investments). Households spend money saved on electric bills on other consumer basket items, which would include a mix of goods and services, some local, some imported, which all rely on different jobs at different wages. Commercial or industrial electric customers experience a savings as making their operations more cost competitive, which returns some positive (though not equal across all type of activities) market share growth (e.g., more sales which means more jobs and other inputs to their operations). Municipal segment savings allow the state/local government entity to redirect dollars into other forms of public spending.

⁵³ *Net Rate Savings* are net of customer out-of-pocket for on-site solar additions under Scenarios 3 and 4. For the County projects, 25 percent of the investment is paid by *Industrial* customers, 25 percent by *Commercial* customers, with the balance funded by outside investors. Small-solar projects in the surrounding counties are assumed to be funded by outside investors. Under scenarios 1 and 2 *net* is equal to gross rate savings.

Figure 25. Cumulative net Rate Savings in Contra Costa County, Proposed CCE structures

The opportunity for the small-solar investment episode (2018 through 2030), for scenarios 3 and 4, to generate “within region” job requirements is determined by how much of the investment dollars connect with (procure from) ‘within region’ construction labor and businesses that provide project components. The allocations of small-solar investment dollars into these two major types of purchases (with additional breakdown on non-labor expenditures) is done using the National Renewable Energy Laboratory (NREL) Jobs and Economic Development Impact (JEDI) small-solar PV JEDI model⁵⁴ (CA) allocation. As shown in Table 20 for scenarios 3 and 4, no less than 50 percent of the various budgets enlists local workforce, and firms that provide supplies or services.

⁵⁴ The Jobs and Economic Development Impact (JEDI) models are user-friendly screening tools that estimate the economic impacts of constructing and operating power plants, fuel production facilities, and other projects at the local (usually state) level. JEDI results are intended to be estimates, not precise predictions. See: http://www.nrel.gov/analysis/jedi/about_jedi.html

Table 20. Local Fulfillment of CCE Budgets (millions of nominal dollars)

	CCA Admin	Solar Invest	Solar O&M	CCA Admin	Solar Invest	Solar O&M
	Scenario 1			Scenario 3		
Budget	\$316	N/A	N/A	\$316	\$456	\$233
In-County						
<i>locally procured</i>	\$189	N/A	N/A	\$189	\$234	\$146
% capture local	60%	N/A	N/A	60%	51%	63%
Surrounding Counties						
<i>locally procured</i>	N/A	N/A	N/A	N/A	\$234	\$146
% capture local	N/A	N/A	N/A	N/A	51%	63%
	Scenario 2			Scenario 4		
Budget	\$316	N/A	N/A	\$316	\$ 827	\$375
In-County						
<i>locally procured</i>	\$189	N/A	N/A	\$189	\$425	\$235
% capture local	60%	N/A	N/A	60%	51%	63%
Surrounding Counties						
<i>locally procured</i>	N/A	N/A	N/A	N/A	\$450	\$219
% capture local	N/A	N/A	N/A	N/A	51%	63%

Resulting Impacts on Jobs

This section will present several views of the job impacts by scenario. As shown in Table 21, Scenario 1 yields the largest annual job impact for the County over the interval – the result of the maximum rate savings under the CCE program. Job impacts are not limited to the direct job requirements from a CCE but include jobs resulting from *multiplier effects* and *competitiveness effects*. Scenario 4 – with the smallest of *net* rate savings for the County’s electric customers poses the largest investment for small -solar across the 5-county economy. This compensates for the reduced role of the rate savings and thus Scenario 4 yields an annual job gain for the 5-county economy, 886 jobs (compared to Scenario 1 with 731). The largest absolute job gain is in Scenario 3, with a total of 922 annual average jobs. As the amount of small solar investment increases (with subsequent O&M spending to follow), the percent of job impact that occurs within the surrounding multi-county region increases (Scenario 4 has 44%). The County’s annual job increase under Scenario 4 however is moderated when compared to Scenario 1. This is understood by (i) all CCE customers’ realizing smaller rate savings when the CCE attempts to invest in *local* solar, combined with (ii) commercial/industrial businesses in the County picking up 50 percent of the solar investment cost. Also, influencing the “surrounding county region” job impact is the fact that a neighboring economy (the County) is experiencing lower electric bills (regardless of the magnitude) and a solar installation “boom” – namely, economic stimulating events. This can create a positive bounce for the surrounding counties on some of the

background business (supplier) transactions as well as with working-age households who commute into the County (this point is illustrated in Figure 26). And when the surrounding region is host to its own solar installation boom, this will engage the Contra Costa County economy as well.

Table 21. Average Annual Employment Impacts 2018 through 2038 (Jobs)

Scenario	Contra Costa	Surrounding 4 Counties	All 5 counties	% in Region
1	681	50	731	7%
2	571	48	619	7%
3	654	268	922	29%
4	474	412	886	44%

For Scenario 4 (with the smallest *net* rate savings and the highest local solar-investment/O&M spend) a time-path of the resulting job impacts is shown in Figure 26. To be clear, the results are not depicting *cumulative* job impacts, simply a plot of each year's resulting impact. After 2030, no more solar installations occur in either region.⁵⁵ The surrounding region remains slightly buoyed with job impacts due to some continued O&M spending and feedback from the Contra Costa economy that is still benefitting now from *gross* rate savings (no more project expenses) and some O&M spending.

Figure 26. Scenario 4 – Annual Job Impacts, 2018 to 2038



⁵⁵ This is because the targeted renewable penetration was met and no new generation is needed by the CCE. If the study looked further out, then replacement solar would begin to have an effect and generate jobs.

Figure 27 helps explain ‘the dip’ in the above *blue* series of positive job impacts (*for Contra Costa*) between 2024 and 2030. The estimated forecast of *net* rate savings follows such a trajectory (becoming *negative* between 2023 and 2030, when some customers bear a portion of the investment cost plus CCE rates are slightly higher than PG&E’s) and even the *local* capture on the solar investment comes off a local maximum in 2020 and a global maximum in 2027 (the latter occurs in the surrounding region as well).

Figure 27. Scenario 4 – Contra Costa’s “Local” Benefit

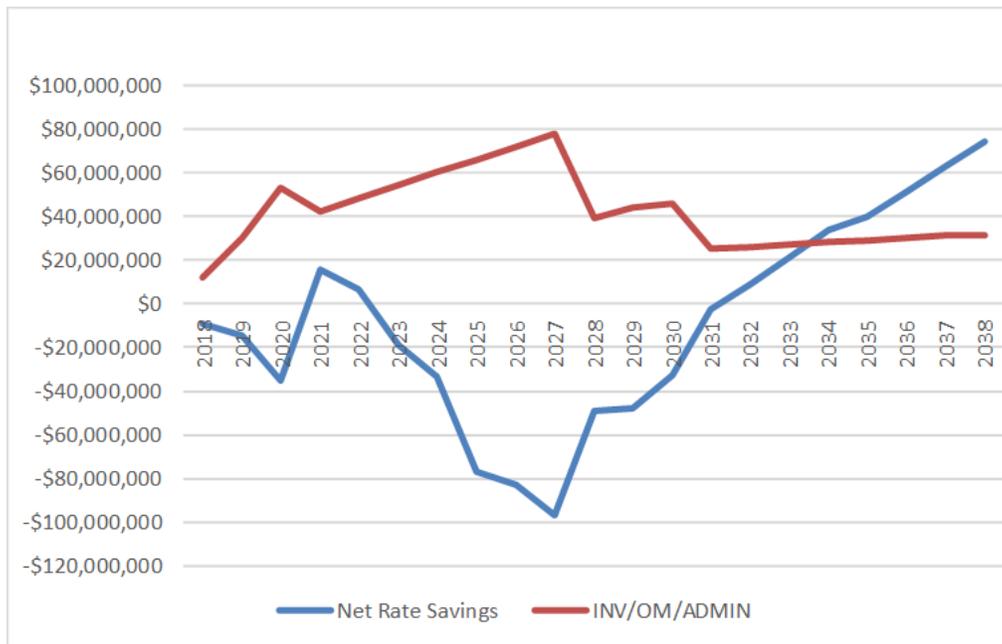
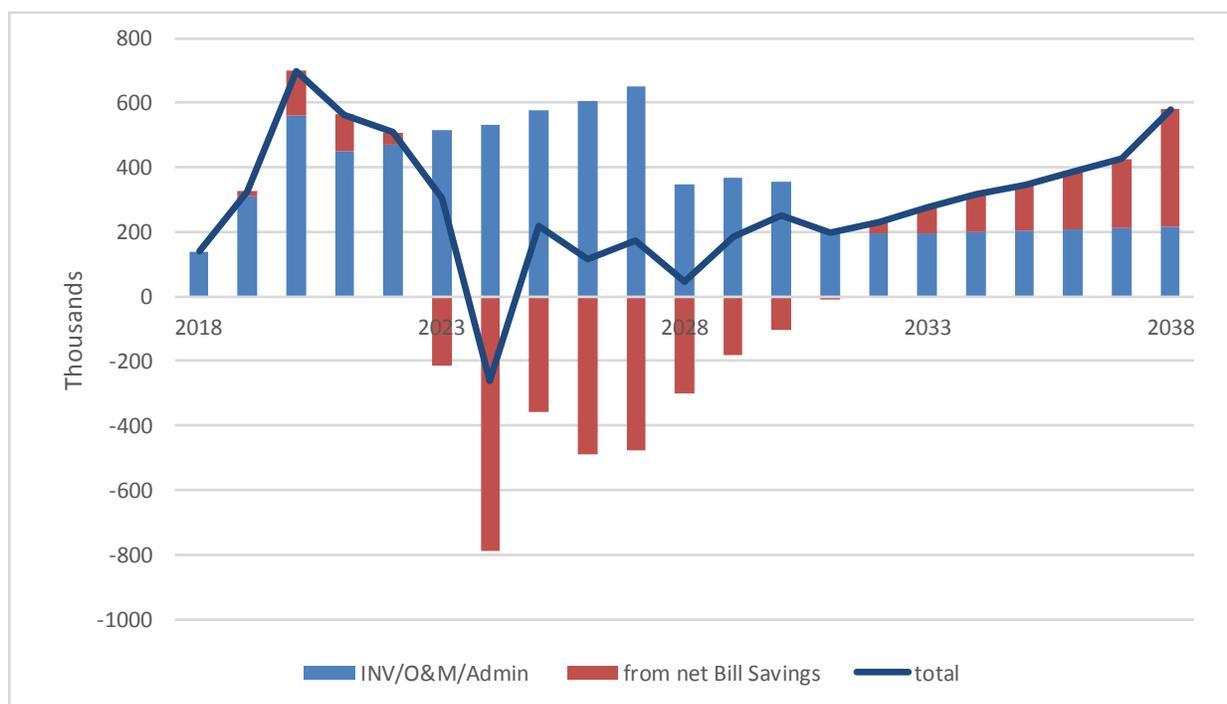
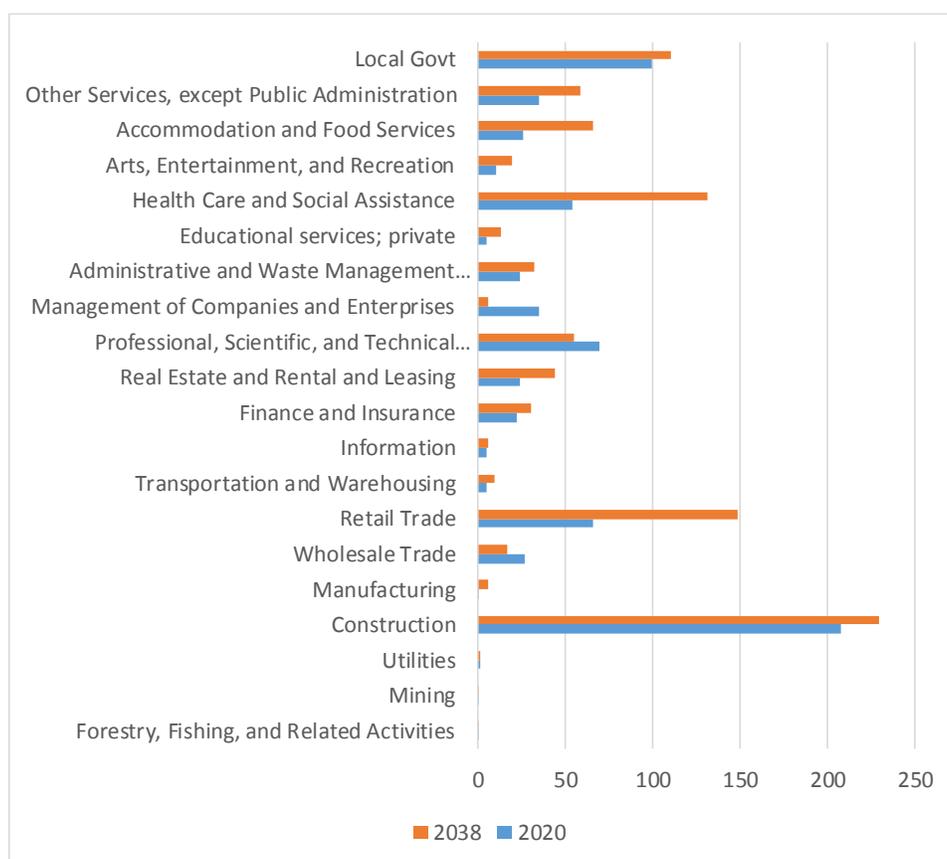


Figure 28 shows what contributes to Contra Costa’s job impact under Scenario 4. The dark blue line is the line from Figure 26. Through 2030, the largest influence on the County’s *positive* job impacts is the stimulus of solar project investment. Afterwards it is the role of *net* Rate Savings exerted through the customers’ roles in the local economy that creates local jobs.

Figure 28. Scenario 4 – Contra Costa Job Impact by Source

A look at two points in the policy interval illustrates the types of jobs that comprise the impact results. In 2020 there are about 700 additional jobs (when solar investment is at a maximum with little of the *net rate savings* realized) and in 2038, about 600 additional jobs in the County (after the investment hang-over is past and only a small influence is exerted through O&M and administrative spending, and the County economy is still experiencing a ramp up of rate savings).

Figure 29 shows a pattern and an order of magnitude for each of the *snapshot* years that is indicative of the major CCE influence on the County’s industry base. In 2020, County job additions are explained foremost by the predominant effect emanating from the CCE scenario – namely solar project investment and program administration (net rate savings are *negative* at this point as a result of C/I customers paying for part of the solar investment cost). So, jobs occur in *Construction*, in *State/Local Government*, in *Professional Technical Services*, and with *Wholesale suppliers*. Project developer overhead payments (part of the investment cost) is why job additions are showing for *Management of Companies and Enterprises*. But not all of the job additions in these sectors are directly related to solar installations. Some of these – as well as jobs gains in other non-investment sectors like health care, and food establishments, and retail – are the result of the initial labor income gains (construction paychecks) which drives added household spending (the *induced* stage of economic multiplier effects), and some are the result of increases in “within county” business-to-business transactions and elevated business needs from the adjacent region (the *indirect* stage of multiplier effects.)

Figure 29. Scenario 4 - Jobs added Among Contra Costa Sectors, 2020 and 2038

In 2038, (the orange series) the predominant ‘economy’ effect from the CCE is the *net* rate savings with a majority benefitting the *residential segment*. Households will redirect these savings into additional household spending (e.g., health care, retail, food establishments). But the municipal segment receives savings as well which drives additional public spending and requires some growth in staff in addition to the local government staff to administer the CCE (an average of 23 *administrative* staff). Commercial and industrial sectors also experience some job increases as their bill savings improve their bottom lines and grow their respective market shares for business. The pronounced gain in local government jobs is more than the (averaged) 23 staff mentioned above. By 2038 the County will have retained a significant number of its working-age residents that would otherwise have out-migrated (under the business-as-usual case) due to a combination of *relative* employment opportunities and inflation adjusted wages. The CCE activity creates job opportunity, mitigates in-county inflation (vis a vis bill savings) so there is real wage appreciation, and helps stem the tide of out-migration of key working-age cohorts. This further bolsters the positive population growth the County was forecast to have (under the BAU case), and local government spending (and staffing) increase on a *per capita* basis. In addition, the S/L government activity increases as the productive capacity of the County grows (in terms of dollars of gross regional product). The *Construction* sector posts strong job increases but now it is more the response to growth in the County (due to CCE influences) and this sector is key during investment (for both residential and non-residential structures) responses to close the gap between actual and optimal capital requirements in a growing economy.

Allocation of Earned Income Gains

A majority but not all jobs added in Contra Costa County will be held by the County's working-age resident households. The same is true for jobs added in the 4-county surrounding region. Which means the household spending effects from the take-home pay on the above impacted jobs occur where the worker *resides*. The above job impacts are measured by *place-of-work*. The commuter from another county registers the induced effects of their earned income on a *place-of-residence* basis.

Again, we focus on Scenario 4 in the year 2020 (year of maximum investment activity that is split 50:50 across both regions). Before we even allocate the impacts across the County boundary, it is helpful to reveal the broad commuting propensity (this is not industry-specific but rather across all activities within an economy) for these two interconnected regions. These relationships are captured in County data on personal (earned) income flows and the journey-to-work data – both federally collected. Table 22 shows the extent of *linkage* on earned income generated in one region and where its workers reside.

Table 22. Earnings-Commuter Reliance between Contra Costa County and the Surrounding region

		Earnings Place-of-Work	
		Contra Costa	Surrounding region
Worker resides	Contra Costa	79%	8.5%
	Surrounding Counties	15%	73%
	Elsewhere	6%	18%
		100%	100%

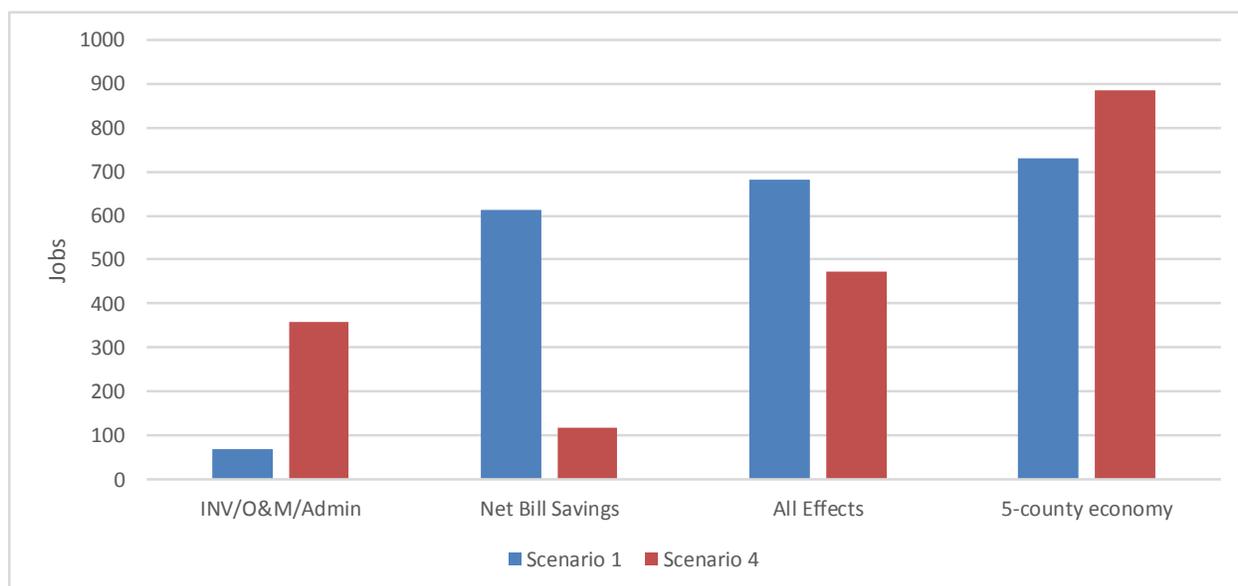
Based on each of the model region's reliance on jobs situated beyond their border there will be "earned income" imported for both Contra Costa and the surrounding region since both economies experience job increases under the CCE activity. For workplace earnings generated in Contra Costa County, 15 percent is earned by residents of the surrounding counties (we ignore the *elsewhere* because it is not part of our macroeconomic consideration). Likewise, of workplace earnings generated in the surrounding counties region, 8.5 percent is by commuters from Contra Costa County. Table 23 shows for 2020 the extent of extra jobs and earnings that will be held by a worker who resides in the other region. Of the 700 jobs added in Contra Costa County in 2020, 83 of these jobs (and \$7 million of earnings) belong to commuters from the adjacent region. Of the 584 jobs added in the surrounding region in 2020, 41 of these jobs (and \$4 million of earnings) belong to commuters from Contra Costa County.

Table 23. Scenario 4 - Earnings Impact by Place-of-Residence, 2020⁵⁶

Scenario 4, Year 2020	Place-of-Work	
	Contra Costa County	Surrounding region
Job impact	700	580
Earnings impact	\$48 million	\$42 million
Earnings per Job	\$86,000	\$87,500
% Commuter earnings (Surrounding counties)	15%	na
% Commuter earnings (Contra Costa)	Na	8.5%
Impact Commuter earnings for Surrounding counties	\$7 million	na
Impact Commuter earnings for Contra Costa	Na	\$4 million
Equiv. # of Surrounding County Commuters	83	na
Equiv. # of Contra Costa Commuters	Na	41

Last, a high-level decomposition of the job impact result in the County is shown in Figure 30 for Scenario 1 (the highest customer savings, no investment in local solar capacity) and Scenario 4. Under Scenario 1 the County realizes most job creation through the effects of rate savings on the County's economy. This response is 5-fold of what Scenario 4 would show as a job impact from rate savings. On the other hand, Scenario 4 exhibits a 5-fold job creation impact from the combined *investment/O&M/administration* effects. Including job creation impacts in the adjacent region of the four surrounding counties, Scenario 4 produces over 100 more jobs (average annual) than Scenario 1. This is predominantly explained by the surrounding region being the location for 50 percent of the small-solar investment that the CCE might choose to fund.

⁵⁶ Earnings per job are weighted estimates.

Figure 30. Average Annual Job Impact in Contra Costa County by Source

Conclusion

A CCE can also offer positive economic development and employment benefits to the County. At the peak, the CCE could create approximately 500 to 700 new jobs in the County plus additional jobs in neighboring counties. For Scenarios 1 and 2, the main driver behind the job growth is the general economic stimulus from injecting more dollars into the local economy via reduced electric rates. When costlier, locally-built renewable projects are emphasized, like in Scenarios 3 and 4, the general economic stimulus driver is replaced by the direct jobs and stimulus created by locally-sited and sourced renewable projects.

Because Contra Costa County's economy is not isolated, CCE formation can have positive effects in neighboring counties, too. This is particularly for the Scenarios emphasizing locally-built renewables, where workers would commute to jobsites in Contra Costa County.

Chapter 6: Other Risks

Aside from the risks identified above, the CCE or the political jurisdictions that are part of the CCE could be at risk for several other reasons. This section addresses some of those risks, which are summarized in Table 24.⁵⁷

Table 24. Summary of CCE Risks

Risk	Magnitude	Mitigation
Financial Risks to CCE Members	Low	Keep CCE JPA's financial obligations separate from jurisdiction's
Procurement-Related Risks (i.e., can't meet rate or GHG targets)	Medium-low	Enter into balanced portfolio of power contracts
Legislative and Regulatory Risks	High	Monitor and advocate at Legislature and CPUC
PCIA Uncertainty	High	Establish rate-stabilization fund to account for volatile PCIA
PCIA Policy Uncertainty	High	Monitor and advocate at Legislature and CPUC
Availability/price of low-carbon resources	Medium	Enter into balanced portfolio of power contracts
Bonding Risk	Low	Monitor and advocate at CPUC

Financial Risks to CCE Members

A CCE is effectively an association of various political subdivisions. The formation documents for the CCE define the rights and responsibilities of each member of the CCE. Given the large number of political subdivisions that might participate in a Contra Costa County CCE, MRW assumes that the Contra Costa County CCE would be formed under a Joint Powers Authority, in much the same way as MCE and Sonoma Clean Power.

The CCE will ultimately take on various financial obligations. These include obtaining start-up financing, establishing lines of credit, and entering into contracts with suppliers. Because a CCE will take on such financial obligations, it is likely very important to the prospective member political subdivisions that the financial obligations of the CCE cannot be assigned to the members.

⁵⁷ Note that this section does not provide legal opinion regarding specific risks, especially those related to the formation or the structure of the Joint Powers Authority under which MRW assumes the CCE will be established.

Thus, it is critical that the Joint Powers Authority and any other structuring documents are carefully drafted to ensure that the member agencies are not jointly obligated on behalf of the CCE (unless a member agency chooses to bear such obligations). The CCE should obtain competent legal assistance when developing the formation documents.⁵⁸

Nonetheless, starting up a CCE often requires a credit-worthy entity to backstop its initial financing. Some, such as CleanPowerSF, use the balance sheet from its existing power enterprise to backstop initial financing. Others have relied upon their host county as a backstop to initial financing. For example, MCE's initial bank loans for working capital were guaranteed by Marin County and the Town of Fairfax. After approximately six years, the CCE had demonstrated its creditworthiness and the guarantees were lifted. Still, the JPA cannot place any financial obligations or risks onto any of its members without that member's approval.

Procurement-Related Risks

Because a CCE is responsible for procurement of supply for its customers, the CCE must develop a portfolio of supply that meets the resource preferences of its customers (e.g., ratio of renewable versus non-renewable supply) while controlling risks (e.g., ratio of short-term versus long-term purchase agreements) and meeting regulatory mandates (e.g., resource adequacy and RPS requirements). Thus, it is tempting to assume that customers would prefer a fully hedged supply portfolio. However, such insurance comes at a cost and a CCE must be mindful of the potential competition from PG&E. Thus, the CCE's portfolio must be flexible while meeting the needs of its customers.

The CCE will likely need to negotiate a flexible supply arrangement with its initial set of suppliers. Such an arrangement is important because the CCE's loads are highly uncertain during CCE ramp-up. Without such an arrangement, the CCE faces the risk of either under- or over-procuring renewable or non-renewable supplies. Excessive mismatches between supply and demand of these different products could expose the CCE's customers to significant purchases or sales in the spot markets. These spot purchases could have a large impact on the CCE's financials.

The CCE will by necessity have to procure a certain amount of short-term supplies. These short-term supplies bring with them price volatility for that element of the supply portfolio. While this volatility is not unexpected, the CCE must be mindful that such volatility could increase the need for reserve funds to help buffer rate volatility for the CCE's customers. Funding such reserve funds could be challenging in this time of low gas prices (resulting in high PCIA charges).

The CCE will be entering the renewable market at an interesting time. While all LSEs must meet the expanded RPS targets by 2030, at least the IOUs are currently over-procured relative to their 2020 RPS targets. Whether the IOUs will attempt to sell off some of their near-term renewable supplies is unknown. However, if the IOUs believe that this is a good time to acquire additional

⁵⁸ Cities such as El Cerrito and Benicia conducted legal analyses when they were considering joining MCE. which should also be consulted.

renewables, the CCE could face stiff competition for renewable supplies, meaning that the green portfolio costs for the CCE might be higher than expected.

Finally, it should be noted that as greater levels of renewables are developed to meet the State's very aggressive RPS goals, it is possible that the traditional peak period will change. Adding significant amounts of solar could depress prices during the middle of the day. This could result in the need to try to sell power to out-of-state market participants during the middle of the day, possibly even at a loss. It could also result in the curtailment of renewable resources (even resources owned or controlled by the CCE). This could force the CCE to acquire greater levels of renewable supplies, thereby increasing costs.

Legislative and Regulatory Risks

As noted above, the CCE must meet various procurement requirements established by the State and implemented by the CPUC or other agencies. These include procuring sufficient resource adequacy capacity of the proper type and meeting RPS requirements that are evolving.⁵⁹ Additional rules and requirements might be established. These could affect the bottom line of the CCE.

PCIA Uncertainty

Assembly Bill 117, which established the CCE program in California, included a provision that states that customers that remain with the utility should be "indifferent" to the departure of customers from utility service to CCE service. This has been broadly interpreted by the CPUC to mean that the departure of customers to CCE service cannot cause the rates of the remaining utility "bundled" customers to go up. To maintain bundled customer rates, the CPUC has instituted an exit fee, known as the "Power Charge Indifference Adjustment" or "PCIA" that is charged to all CCE customers. The PCIA is intended to ensure that generation costs incurred by PG&E before a customer transitions to CCE service are not shifted to remaining PG&E bundled service customers.

Even though there is an explicit formula for calculating the PCIA, forecasting the PCIA is difficult, because many of the key inputs to the calculation are not publicly available, and the results are very sensitive to these key assumptions. For PG&E, the PCIA has varied widely; for example, at one time the PCIA was negative.

Current CCEs have chosen to have customers bear the financial risk associated with the level of exit fees they will pay to PG&E. Thus, for a customer taking CCE service to be economically better off (i.e., pay less for electricity), the sum of the CCE charges plus the PCIA must be lower than PG&E's generation rate.

This risk can be mitigated in two ways. First, as discussed in more detail elsewhere, a rate stabilization fund can be created. Second, the CCE can actively monitor and vigorously participate in CPUC proceedings that impact cost recovery and the PCIA.

⁵⁹ Rules to establish RPS requirements under the new 50% RPS mandate are currently being debated at the CPUC.

Impact of High CCE Penetration on the PCIA

Currently, the PCIA calculation is based on the cost and value of a utility's portfolio, without regard to how much of that portfolio is to be paid for by bundled customers and how much by Direct Access (DA) and CCE customers. As such, the PCIA is not affected by the number of DA/CCE customers.

Currently, for bundled customers the rate impacts associated with fluctuating PCIA's are relatively small, but this will change as the number of DA/CCE customers grows. At some point, bundled customers' rates may experience marked volatility as the impacts of the annual PCIA rate swings reverberate to bundled rates. This may be unacceptable to ratepayer advocates and the Commission.

The PCIA rate volatility in part reflects changes to the utilities' generation costs, which are appropriately reflected in bundled customers' rates. But, often to a large degree, it reflects changes to the market price benchmark, which should not be relevant to bundled customer rates. For example, for a utility with flat RPS costs, a reduction to the market price benchmark for renewable power would increase the RPS-related PCIA, which would reduce bundled rates, even though there was no change in RPS costs. This could also happen in the reverse direction, increasing bundled rates when there is no increase in underlying generation costs.

Once DA/CCE load gets large enough that there are real stranded contracts, we suspect that the Commission is going to look much more closely at the value of these stranded contracts (and how to get the most value for them).

Impact of High CCE Penetration on Low-Carbon (Hydro) Resources

Virtually all the CCEs forming in California include carbon reduction as a goal. As the analysis has shown, CCEs will likely need to purchase both RPS-eligible power and other carbon-free power to meet their goals, namely large hydropower. This has been the approach used by MCE, Peninsula Clean Power, and Silicon Valley Clean Power, who all beat PG&E's GHG emissions rate through contracts for hydropower. This increased demand for carbon-free hydropower can change the "supply-demand" balance and in theory increase the cost of these resources. However, to put this in perspective, the amount of hydropower assumed in the technical study is very modest compared to its availability. For example, in the Pacific Northwest, hydroelectric facilities generated approximately 128,000 GWh of electricity, and over the past 5 (drought) years, California hydroelectric resources generated 25,000 GWhs of electricity. In contrast, the technical study assumed only 0.4-1.5 GWh/year of hydropower—well under one percent of the available resource. Furthermore, the assumed hydro premium, \$10/MWh over standard market power, is much higher than the current \$1.50-\$2.50/MWh premiums being seen. Thus, a certain amount of market tightening is already built into the study.

Nonetheless, to address this risk, the Contra Costa County CCE should consider locking in longer-term contracts for non-RPS eligible resources early in the process so as to guarantee their availability at a reasonable price in the longer term when there could be greater demand for them.

Bonding Risk

Pursuant to CPUC Decision 05-12-041, a new CCE must include in its registration packet evidence of insurance or bond that will cover such costs as potential re-entry fees, specifically, the cost to PG&E if the CCE were to suddenly fail and be forced to return all its customers back to PG&E bundled service. Currently, a bond amount for CCEs is set at \$100,000.

This \$100,000 is an interim amount. In 2009, a Settlement was reached in CPUC Docket 03-10-003 between the three major California electric utilities (including PG&E), two potential CCEs (San Joaquin Valley Power Authority and the City of Victorville), and The Utility Reform Network (TURN) concerning how a bonding amount would be calculated. The settlement was vigorously opposed by MCE and San Francisco and never adopted.

Since then, the issue of CCE bond requirements has not been revisited by the CPUC.⁶⁰ If it is, the bonding requirement will likely follow that set for Energy Service Providers (ESPs) serving direct access customers. This ESP bond amount covers PG&E's administrative cost to reintegrate a failed ESP's customers back into bundled service, plus any positive difference between market-based costs for PG&E to serve the unexpected load and PG&E's retail generation rates. Because the ESP bonding requirement has been in place, retail rates have always exceeded wholesale market prices, and thus the ESP's bond requirement has been simply equal to a modest administrative cost.

If the ESP bond protocol is adopted for CCEs, during normal conditions, the CCE Bond amount will not be a concern. However, during a wholesale market price spike, the bond amount could potentially increase to millions of dollars. But the high bond amount would likely be only short term, until more stable market conditions prevailed. Also, it is important to note that high power prices (that would cause a high bond requirement) would also depress PG&E's exit fee and would also raise PG&E rates, which would in turn likely provide the CCE sufficient headroom to handle the higher bonding requirement and keep its customers' overall costs competitive with what they would have paid had they remained with PG&E. As discussed above, JPA member entities would not be individually liable for any increase in the bond amount.

⁶⁰ On January 30, 2017 the CPUC set a pre-hearing Conference to begin a process to address CCE bonding requirements.

Chapter 7: Comparative Analysis of CCE Options

Having the County and cities within the County form their own JPA and CCE Program is not the only possibility for CCE participation. First, the Counties and/or its cities may join Marin Clean Energy (MCE). In fact, 5 cities in the County—El Cerrito, Lafayette, Richmond, San Pablo, Walnut Creek—are already members of MCE. These cities joined between 2013 and 2016, and have full standing on MCE’s Board of Directors. Second, the County and/or its cities could join the East Bay Community Energy (Alameda County) CCE. While this CCE has just been formed, with its JPA board having been seated in January 2017, it aims to begin power delivery in late 2017. Furthermore, the County and each city need not join one or the other CCE *en masse*, but instead can join one or the other CCEs individually (or neither).

This chapter presents the benefits and drawbacks of joining either MCE or EBCE, forming a new CCE with the County and the cities not currently in MCE (which has been the focus of most of the analysis in this report), or remaining with PG&E. To the extent possible, this chapter considers the rate-competitiveness, GHG reduction, local economic development, local control and governance, cost risks, and CCE formation timing of each option. Some of the benefits may depend upon how much of the County chooses which path. Each community chooses for itself; thus, it is possible to have some join MCE, some join EBCE, and others remain on PG&E service. To the extent that it matters, this will be highlighted in the sections that follow.

Note that MRW & Associates are not attorneys, and that the MCE and EBCE JPA agreements are legal documents. Therefore, nothing herein should be interpreted as a legal opinion – only an informed lay-reading of the documents. MRW would strongly recommend that Contra Costa County and any city considering becoming a member of MCE or EBCE have its counsel conduct a thorough review of the respective JPA and related documents prior to committing to a CCE.

Table 25 below summarizes our results. While it is desirable to quantify some (or all) of the criteria, to do so would be an exercise in false precision. First and foremost, two of the potential CCE options are with entities which, while potentially viable, do not exist. Without power contracts, portfolios, or procurement guidelines and policies, it would be unwise to claim that EBCE or a potential Contra Costa-only CCE would have rates or greenhouse gas emissions higher or lower than the other. Comparisons against MCE can be somewhat more reasonably asserted; however, its stated goals—greater renewable energy content, lower greenhouse gas emissions, local generation, and comparable rates—are nearly identical to those stated by EBCE, so as to make long-range rate and emissions distinctions immaterial. This contrasts with PG&E, whose power portfolios, procurement plans, and costs are readily available through various filings and applications it has made before the CPUC. Thus, the qualitative comparisons provided in the table do not provide sharp distinctions between the CCE options. All these options are expected to provide similar rates and GHG emissions, with differences arising from variations in the priorities and procurement decisions of the individual governance boards. What truly distinguishes these options are primarily governance options (i.e., in-county only versus shared with other entities) and the amount of risk assumed (i.e., developing or signing on with a new CCE versus joining one with a record of satisfactory performance).

Each of the lines on the table are discussed in greater detail in the sections that follow.

Table 25. Comparison of Contra Costa CCE Options

Criterion	Form CCCo JPA	Join MCE	Join EBCE	Stay with PG&E
Rates	Likely lower	Likely Lower	Likely Lower	Base
GHG Reduction Potential Over Forecast Period	Some	Some	Some	Base
Local Control/Governance	Most	Some	Some	None
Local Economic Benefit Potential	Greatest	Some	Some	Minimal
Start Up Costs/Cost to Join	Low, but greater risk ⁶¹	None ⁶²	None ⁶²	None
Level of Effort	Greatest	Minimal	Greater	None
Program Risks	Greatest	Minimal	Some	Base
Timing (earliest)	Late-2018	Late-2017	Mid-2018	N/A

Rates

In general, any of the three CCE options can result, in the long run, with rates that are at or slightly below those of PG&E. This is not to say that in some years PG&E's rates may be lower, or that one CCE option would consistently have rates that are lower than the others. Rather, given that a CCE's rates are a function of its communities' values—amount of local renewable generation, promotion of energy efficiency or distributed generation, overall rate minimization—and that two of the three CCEs being compared do not yet exist, let alone have rate or procurement policies, MRW cannot assert that one CCE option will have lower rates than the other two. Both MCE and EBCE have commitments to higher-cost local renewable development, which suggests that they are willing to trade off somewhat lower rates for other benefits. A

⁶¹ Start-up costs provided by the County or others are likely to be reimbursed by the JPA.

⁶² Costs already spent for consulting/technical study will likely not be reimbursed.

Contra Costa CCE that focuses more on rate reduction could in principle offer marginally lower rates than the other two.

GHG Reduction

For climate action planning and reporting purposes, the amount of GHG reduction that can be attributed to a CCE formation is a function of the difference between the average GHG emissions from PG&E and that of the CCE. PG&E’s power portfolio is already relatively “clean,” with large fractions coming from not only qualifying renewables but also nuclear power (through 2024) and large hydroelectric generators. As Table 26 shows, 59% of PG&E’s 2015 power came from GHG-free resources. This number would be closer to 67% GHG-free but for the poor hydroelectric generation due to the ongoing drought.⁶³ Therefore, for any CCE to have a reduced average carbon footprint requires not only the same or greater amount of qualifying renewable generation, but additional sources of GHG-free generation.

Table 26. PG&E and MCE Power Content (2015)

	PG&E 2015	MCE 2015
Eligible renewable	30%	56%
Large Hydro	6%	12%
Nuclear	23%	0%
GHG-Free subtotal	59%	68%
Unspecified/Market	17%	25%
Natural Gas	25%	12%
Fossil subtotal	41%	32%

An approach taken by some of the currently operating Northern California CCEs is to (a) use more qualifying renewable generation than PG&E, and (b) contract with and use power from large hydroelectric resources. This is shown in MCE’s power content mix, and to the extent possible, what was modeled here for Contra Costa County and for MRW’s study of an Alameda County CCE.

Given that both MCE and EBCE have made GHG reductions a very high priority, one can reasonably assume that either will have some GHG-emissions benefit relative to PG&E, but there is no concrete rationale to assume that either MCE or EBCE will have a significantly-lower GHG emissions rate than the other.

Local Economic Benefits

As noted earlier in the report, the amount of local economic benefits is a function of rate reduction and local construction and CCE staffing. The number of local renewable energy projects will be a function of at least two factors. The first is any cost competitiveness advantage of renewable resources in the County; i.e., others will want to build renewable generation in the County because of cost advantages (including interconnection ease). Second, local generation

⁶³ However given climate change, one can sensibly argue that the lower-than-historic-average hydroelectric output in California seen over the past few years may be more predictive than the historical average.

development will be fostered by a preference for local generation by the CCE serving Contra Costa County. While all three CCE options have expressed a preference for “local” renewables, the extent to which these three programs might develop local renewable generation facilities within the County remains uncertain. MCE has already invested in Contra Costa County, with a new utility-scale solar project in Richmond and numerous individuals taking advantage of its rooftop solar program. Nonetheless, in the long run MRW would expect that a Contra Costa CCE would have the greatest interest in developing in-county renewables and thus could potentially have the greatest positive economic impact. Teaming with either of the other CCEs would dilute the interest, as the CCE would have to consider economic development in its non-Contra Costa communities as well. Given the particularly strong interest of the EBCE group in local renewables, the notion that “local” might encompass the whole “East Bay,” and the fact that Contra Costa cities might have greater say in the formation of generation polities with a new group like EBCE than a more established one like MCE all suggest that EBCE might be more responsive in developing in-county renewables than MCE. On the other hand, MCE has a commanding head start, having already developed renewable projects in the County.

Contra Costa County makes up but a small fraction of PG&E’s service area. While PG&E’s local community engagement is admirable, it cannot focus on the County in a way that a smaller CCE can. As such, any of the three CCE scenarios will likely result in greater local economic benefits than remaining with PG&E.

CCE Governance: Voting

How each community is represented on a CCE’s governing board (generally a board of directors) is laid out in its JPA agreement. Per its current JPA agreement, EBCE will have a two-stage vote: under most circumstances, each board member (each representing a single entity) would have one vote, regardless of his or her entity’s size. That is, both Oakland and Piedmont would have an equal vote. In the event of a non-unanimous affirmative vote, three cities can call for a weighted vote. In that case, each Representative Board Member’s vote would be weighted according to the size (in kilowatt-hours) of the entity being represented. These two voting shares are shown in Table 27.

As noted in Table 28 if EBCE consisted of Alameda County alone, the combination of the three largest entities (Oakland, Fremont, plus Hayward or Berkeley) could carry the weighted vote. If all of Contra Costa County joined EBCE, then it would take the five largest entities (Oakland, Fremont, Hayward, Unincorporated Contra Costa County plus Berkeley or Concord) to carry the vote.

Table 27. EBCE Voting Shares, With and Without Contra Costa⁶⁴

	Simple Voting		Load-Weighted Voting*	
	Alameda Only	Alameda + Contra Costa	Alameda Only	Alameda + Contra Costa
Oakland	8.3%	3.7%	24.8%	17.5%
Fremont	8.3%	3.7%	16.2%	11.4%
Hayward	8.3%	3.7%	10.1%	7.1%
Berkeley	8.3%	3.7%	8.5%	6.0%
San Leandro	8.3%	3.7%	6.4%	4.5%
Livermore	8.3%	3.7%	6.2%	4.4%
Unincorporated Ala.	8.3%	3.7%	6.4%	4.5%
Other Alameda Cities	41.7%	18.5%	14.9%	8.3%
Alameda Total	100.0%	44.4%	100.0%	63.6%
Unincorporated C.C.		3.7%		9.0%
Concord		3.7%		5.1%
Pittsburg		3.7%		4.6%
Antioch		3.7%		3.7%
San Ramon		3.7%		3.2%
Brentwood		3.7%		2.1%
Danville		3.7%		1.7%
Martinez		3.7%		1.4%
Pleasant Hill		3.7%		1.4%
Oakley		3.7%		1.1%
Orinda		3.7%		1.0%
Hercules		3.7%		0.7%
Pinole		3.7%		0.6%
Moraga		3.7%		0.5%
Clayton		3.7%		0.3%
Contra Costa Total	N/A	55.6%	N/A	36.4%
<i>*Only in cases where called upon by 3 Board Members</i>				

Table 28. EBCE Minimum Cities Needed to Carry Weighted Vote

Alameda Only	3 cities	Oakland, Fremont + Hayward or Berkeley
Alameda + Contra Costa	5 cities	Oakland, Fremont, Hayward, Unincorporated Contra Costa Co. + Berkeley or Concord

⁶⁴ It should be noted that two cities in Alameda County opted to not join the CCE at this time. Should they join, that could change the voting shares. Similarly, if not all Contra Costa jurisdictions join either MCE or EBCE, the voting shares will be different.

MCE's voting structure differs from EBCE's in two important ways. First, each board member's vote is a weighted. Half of each board member's weighting is equal to his or her entity's share of MCE's total load. The other half is an equal share for each entity. Thus, if a community is one of 26 members representing 18% of MCE's load, the board member's vote would be 10.9% ($18\% \times (1/2) + (1/26) \times (1/2) = 9\% + 1.9\% = 10.9\%$) Second, multiple entities have the option to be represented by a single board member. For example, Napa County and all the towns/cities within the County are represented by a single board member. This consolidated seat allows for potentially less administrative burden on the represented entities and "streamlines communication and policy setting." On the other hand, it effectively requires the communities with a joint board member to vote as a bloc, and while the bloc maintains the same voting share, it can reduce the "voice" of the communities: one person to speak on their behalf rather than, say, five, or six (or more).

Table 29 shows what the voting shares might be if all the Contra Costa communities joined MCE and each claimed its own board member. Together, the Contra Costa communities (including those already in MCE) would represent 71% of MCE's load and have a total 62% of the voting share.

Table 29. MCE Voting Shares With Each Contra Costa Community Having Its Own Board Member

VOTING SHARES	Entity Share	Load Share	Voting Share
Antioch	1.3%	2.8%	4.1%
Brentwood	1.3%	1.6%	2.9%
Clayton	1.3%	0.3%	1.5%
Concord	1.3%	3.9%	5.2%
Danville	1.3%	1.3%	2.6%
Hercules	1.3%	0.6%	1.8%
Martinez	1.3%	1.1%	2.4%
Moraga	1.3%	0.4%	1.6%
Oakley	1.3%	0.8%	2.1%
Orinda	1.3%	0.8%	2.0%
Pinole	1.3%	0.5%	1.7%
Pittsburg	1.3%	3.5%	4.7%
Pleasant Hill	1.3%	1.0%	2.3%
San Ramon	1.3%	2.4%	3.7%
Unincorporated Contra Costa County	1.3%	6.8%	8.1%
New Contra Costa Members	19.2%	27.6%	46.8%
Existing MCE Contra Costa Members	6.4%	8.0%	14.4%
TOTAL CONTRA COSTA COUNTY	25.6%	35.6%	61.2%
Rest of MCE	24.4%	14.4%	38.8%

CCE Governance: Other

The proposed EBCE JPA Agreement also calls for a formal Community Advisory Committee (Section 4.9). The relevant section states that the purpose of the Committee:

“shall be to advise the Board of Directors on all subjects related to the operation of the CCA Program ... with the exception of personnel and litigation decisions. The Community Advisory Committee is advisory only, and shall not have decision-making authority... The Board shall appoint members of the Community Advisory Committee from those individuals expressing interest in serving, and who represent a diverse cross-section of interests, skill sets and geographic regions.”

The Chair of the Community Advisory Committee will serve as a non-voting *ex officio* member of the EBCE Board of Directors.

MCE has no analogous official community advisory committee originating from its JPA agreement. Nonetheless, there is a “Community Power Coalition” that provides input to MCE (*see*, <https://www.mcecleanenergy.org/community-power-coalition/>). The Coalition works “on a variety of issues ranging from local renewable energy project development – like MCE Solar One in Richmond – to outreach for MCE’s Spanish-speaking constituents, to environmental justice and consumer protection issues affecting MCE’s low-income customers.”

The recitals to EBCE’s JPA agreement lay out what can be described as its envisioned values. Besides offering competitive rates and lowering greenhouse gasses, this includes (Recitals, Section 6):

- Establishing an energy portfolio that prioritizes the use and development of local renewable resources and minimizes the use of unbundled renewable energy credits;
- Promoting an energy portfolio that incorporates energy efficiency and demand response programs and has aggressive reduced consumption goals;
- Demonstrating quantifiable economic benefits to the region (e.g. union and prevailing wage jobs, local workforce development, new energy programs, and increased local energy investments);
- Recognize the value of workers in existing jobs that support the energy infrastructure of Alameda County and Northern California. The Authority, as a leader in the shift to a clean energy, commits to ensuring it will take steps to minimize any adverse impacts to these workers to ensure a “just transition” to the new clean energy economy;
- Delivering clean energy programs and projects using a stable, skilled workforce through such mechanisms as project labor agreements, or other workforce programs that are cost effective, designed to avoid work stoppages, and ensure quality;
- Promoting personal and community ownership of renewable resources, spurring equitable economic development and increased resilience, especially in low income communities;
- Provide and manage lower cost energy supplies in a manner that provides cost savings to low-income households and promotes public health in areas impacted by energy production; and

- Create an administering agency that is financially sustainable, responsive to regional priorities, well managed, and a leader in fair and equitable treatment of employees through adopting appropriate best practices employment policies, including, but not limited to, promoting efficient consideration of petitions to unionize, and providing appropriate wages and benefits.

Contra Costa communities considering joining EBCE should consider these enunciated values prior to committing to membership.

Timing and Process to Join/Form

The timing required to serve Contra Costa businesses and residents vary markedly among the CCE options. The quickest path the CCE service would be to join with MCE. The first step for a community to join MCE is for its governing body or representative (e.g., city manager) to provide MCE a non-binding letter of interest. The entity's governing body would then need to adopt a resolution requesting MCE membership; have a first reading of an ordinance to join MCE; execute a memorandum of understanding between the entity and MCE to address preliminary data and communication issues; and provide a signed request for PG&E to provide MCE its load data. These steps would need to occur during MCE's "inclusion period" which currently runs from December 1, 2016 through May 31, 2017. Only communities in Contra Costa County are eligible to request MCE membership during this period.

MCE would then evaluate the impact of the new load on its system. If the net result of adding the new community is that MCE's rates would increase, then that community's membership would be tabled until a future date. If the MCE analysis shows that adding the community is favorable, then the MCE Board would vote to accept (or not) the community into MCE. At that point, the local ordinance for MCE membership would receive a second reading and adoption. MCE would then modify its official Implementation Plan to reflect the new community, and submit the updated plan to the California Public Utilities Commission. Once approved (none have been rejected), the phase-in of the community into MCE can occur.

Based on MCE's currently Inclusion Period, Contra Costa County and the jurisdictions not already served by MCE could begin MCE service as early as late 2017.

Although it has just recently formed, the EBCE board has extended an offer to interested Contra Costa communities to join EBCE. In a letter from Chris Bazar, Director, Alameda County Community Development Agency, EBCE would welcome Contra Costa members into its Phase 2 or Phase 3 rollout.⁶⁵

The current EBCE JPA documents states in Section 3.1, Addition of Parties:

Subject to Section 2.2, relating to certain rights of Initial Participants, other incorporated municipalities and counties may become Parties upon (a) the adoption of a resolution by the governing body of such incorporated municipality or county requesting that the incorporated municipality or county, as the case may be, become a member of the

⁶⁵ The letter suggests that Phase 2 would commence in the summer of 2018 and Phase 3 in Fall 2018 or Spring 2019.

Authority, (b) the adoption by an affirmative vote of a majority of all Directors of the entire Board satisfying the requirements described in Section 4.12, of a resolution authorizing membership of the additional incorporated municipality or county, specifying the membership payment, if any, to be made by the additional incorporated municipality or county to reflect its pro rata share of organizational, planning and other pre-existing expenditures, and describing additional conditions, if any, associated with membership, (c) the adoption of an ordinance required by Public Utilities Code Section 366.2(c)(12) and execution of this Agreement and other necessary program agreements by the incorporated municipality or county, (d) payment of the membership fee, if any, and (e) satisfaction of any conditions established by the Board..

Thus, a Contra Costa community would need to adopt a resolution requesting membership in the EBCE, the board of Directors of EBCE would have to vote to authorize the applying community's membership, followed by the applying entity passing an ordinance to join. To be part of the Phase 2 rollout, a City would have need to have an ordinance passed by June 30, 2017.

Implementing a Contra Costa County only CCE would likely have a time line similar to joining EBCE. If the County and its cities were committed to this path, it could potentially begin service as early as 2018. This is consistent with Peninsula Clean Energy, which went from putting out an RFP for a technical study to Phase 1 implementation in 18 months (April 2, 2015 to October 1, 2016). A more measured timeline would suggest that a new Contra Costa CCE would spend much of 2017, planning and generating local support, with implementation beginning in late 2018 or 2019.

Costs to Join the CCE

This section discusses direct, non-reimbursable costs to cities for joining either EBCE or MCE. So far, cities joining MCE have not had to pay for any of the costs incurred by MCE to plan for or integrate their load. They have often spent on the order of \$10,000 to \$15,000 for consultants to evaluate the risks to the city and its residents and businesses that could come from joining MCE. Both MCE and EBCE have extended a no-cost opportunity to join to the Contra Costa jurisdictions who are not already members of MCE.

The start-up costs for a new Contra Costa CCE would be significant—Alameda County has committed \$3.4 million to its effort. However, consistent with other CCEs, these costs would be initially reimbursed to the County and funding cities by a loan taken out by the CCE's JPA, which would in turn be paid down via CCE rates over the initial few years. As such, the only "cost to join" a Contra Costa CCE felt by any individual city would be indirect at best (i.e., asked to backstop any CCE loads with the entities' credit).

Exiting the CCE

MCE's JPA Section 7.0 lays out the process and ramifications of a MEC member withdrawing from the JPA. First, an entity may withdraw from the JPA within 30 days of its notification of joining the JPA, assuming that MCE has not entered into any wholesale power agreements to serve the entity. (Section 7.1.1.1) After MCE has entered into wholesale power agreements to serve the entity, the entity may withdraw from MCE, effective the beginning of the JPA's fiscal

year by giving at least 6 months' written notice of its intent to withdraw. The withdrawing entity may be subject to "certain continuing liabilities" as laid out in Section 7.3:

7.3 Continuing Liability; Refund. Upon a withdrawal or involuntary termination of a Party, the Party shall remain responsible for any claims, demands, damages, or liabilities arising from the Party's membership in the Authority through the date of its withdrawal or involuntary termination, it being agreed that the Party shall not be responsible for any claims, demands, damages, or liabilities arising after the date of the Party's withdrawal or involuntary termination. In addition, such Party also shall be responsible for any costs or obligations associated with the Party's participation in any program in accordance with the provisions of any agreements relating to such program provided such costs or obligations were incurred prior to the withdrawal of the Party. The Authority may withhold funds otherwise owing to the Party or may require the Party to deposit sufficient funds with the Authority, as reasonably determined by the Authority, to cover the Party's liability for the costs described above. Any amount of the Party's funds held on deposit with the Authority above that which is required to pay any liabilities or obligations shall be returned to the Party.

Neither the precise calculation of the liabilities nor how it would be collected is specified.

The proposed EBCE JPA Agreement contains no language concerning a community's exit from EBCE or the JPA.

Remaining With PG&E

Although this study suggests CCE program options would likely produce both environmental and economic benefits for the jurisdictions included in the study, continuing service with PG&E remains an option for not only a community but also for any individual or business whose community has selected CCE service (i.e., each individual account maintains its right to opt-out of CCE service). There are benefits of remaining with PG&E, even at a community level. First, remaining with PG&E takes no city action. Thus, a city's leadership and staff can concentrate their limited resources on matters that may be more pressing. Second, PG&E is regulated by the State via the California Public Utilities Commission (CPUC), which oversees its power procurement and approves its rates. While CCEs are partially regulated by the CPUC (e.g., ensuring that the CCE complies with any applicable laws), they are not subject to rate regulation. Some may see State oversight as a benefit, with an official "watchdog" overseeing power supply and procurement, while others might see the local CCE board accountability as a benefit. Third, PG&E is much larger than any of the CCE options that Contra Costa communities might pursue, which (as discussed) might reduce community input and value but also provide some economies of scale. For example, one poor power contract entered might have significant rate or operational ramifications for a CCE. For PG&E, given its size, the impact of that same poor contract would be diluted. Lastly, simply because a Contra Costa community does not join a CCE in 2017 or 2018 does not necessarily preclude it from doing so in the future, although waiting may result in an "entry fee" or perhaps a high PCIA rate.

Summary

The following lays out the principal benefits and risks of each of the options considered.

Potential Benefits of Forming Contra Costa CCE (relative to joining MCE or EBCE)

- More local control (voting shares not diluted)
- Can form JPA and policies to fully reflect County interests and values
- Greatest potential for local economic development (due largely to more local control)
- Even if formed, individuals may still select PG&E as their power provider

Potential Risks/Downsides of Forming Contra Costa CCE (relative to joining MCE or EBCE)

- Commitment of County and city resources to establish a new CCE agency
- Higher risks due lack of experience, fewer partners
- Would need to establish programs, contractors, credit, etc.
- Longest time line to begin enrolling customers
- Given MCE's presence in five Contra Costa communities, potential customer confusion with multiple CCEs in the same county

Potential Benefits of joining MCE (relative to joining EBCE)

- Five other Contra Costa County communities have already joined
- Established, successful program
- Credit capacity and programs in place
- Likely easier transition/implementation
- Able to enroll customers sooner than EBCE
- Programs that create jobs and economic benefits could be implemented more quickly

Potential Risks/Downsides of joining MCE (relative to joining EBCE)

- May have less Board representation (if all of Contra Costa County and its jurisdictions are represented by a shared seat)
- May be less of a "fit" compared to East Bay identification and sensibilities (or, for some cities, this may be a benefit)
- Programs are already in place; less/minimal input into their formation
- Joining a large board serving a very diverse customer base and geography

Potential Benefits of joining EBCE (relative to joining MCE)

- Coming in closer to the "ground floor" — opportunity to influence policy direction and program development
- May be more mission or cultural alignment (East Bay vs. Marin) (or perhaps for some communities, not)

- Board will more likely be one seat per member jurisdiction (not a shared seat)
- Weighted voting process is a little clearer
- EBCE working on a local development business plan with emphasis on local power production in the East Bay

Potential Risks/Downsides of joining EBCE (relative to joining MCE)

- Take longer to enroll County communities
- Take longer for job-creating programs to get up and running
- May be a small fish among some very large fish (Oakland, Hayward)
- Union focused policies may be difficult for some (or preferable)
- Given MCE's presence in five Contra Costa communities, potential customer confusion with multiple CCEs in the same county

Potential Benefits of Remaining with PG&E (relative to joining or forming a CCE)

- Experienced provider
- State regulatory protection
- Continuity- same firm provides all services
- No action needed by City/County—status quo
- May be able to join a CCE at a later date (but perhaps at some cost)

Potential Risks/Downsides Benefits of Remaining with PG&E (relative to joining or forming a CCE)

- Higher GHG emissions
- Less local renewable generation
- Higher electricity rates than CCE rates under most scenarios
- Less local control
- Less local input into policies and offerings
- Less local economic development

Chapter 8: Other Issues Investigated

Synergies on the Northern Waterfront

Contra Costa County has an ongoing initiative to economically develop its Northern Waterfront. The Northern Waterfront stretches from the City of Hercules at San Pablo Bay, along the southern shore of the Carquinez Straight and Suisun Bay, and out to the San Joaquin Delta region of Oakley. The County's Northern Waterfront Economic Development Initiative is a regional cluster-based economic development strategy with a goal of creating 18,000 new jobs by 2035. The Initiative leverages existing competitive advantages and assets by focusing on advanced manufacturing sub-sectors in five targeted clusters (advanced transportation fuels, bio-tech/bio medical, diverse manufacturing, food processing, and clean tech).

To assess the potential positive impacts a CCE might have on this Area, the study looked at the Northern Waterfront to assess local generation potential within the area. Of the potential 3,350 MW of solar resources in the County, approximately 40% lies within the Northern Waterfront. As shown in Table 30, there are over 700 potential solar sites in the area, which could theoretically generate over 2,000 GWhs. Of these sites, over 800 MW have the highest potential ranking, meaning that they are the most appropriate for actual development. In fact, all the local solar capacity specified in Scenarios 3 or 4 could be met at sites in the Northern Waterfront alone.

Table 30 Solar Potential in the Northern Waterfront

Location	Solar Sites	PV Potential (MW)	PV Production (GWh)	Build Cost (\$ Thousands)
Antioch	189	327	524	\$747,130
Concord	108	191	306	\$442,015
Crockett	21	58	93	\$125,187
Hercules	52	90	144	\$200,512
Martinez	139	300	480	\$629,130
Oakley	43	76	121	\$178,390
Pinole	17	24	39	\$57,208
Pittsburg	153	298	477	\$679,851
Rodeo	14	35	57	\$85,875
Grand Total	736	1,400	2,241	\$3,145,298

How much solar could actually be sited in the Northern Waterfront would depend upon (a) the degree to which there is competition for sites for perhaps higher-value projects and (b) the CCE's policies toward fostering local projects.

In addition to this renewable potential, the Northern Waterfront also hosts six major power plants (Table 31). In addition to these, the refineries in the area also generate much of their own power.

A Contra Costa CCE could contract with one of more of these facilities to provide the CCE’s Resource Adequacy Requirements or a portion of its energy needs. Alone, a Contra Costa CCE would not be able to use all—or even most—of the power produced by any of these or other major power plant of this magnitude (e.g., the cancelled Oakley power plant).

Table 31. Natural Gas Power Plants in the Northern Waterfront

Plant	Location	Capacity (MW)	Year in Service	Owner	Type
Crockett Cogen	Crocket	275	1995		Steam-Cogen
Los Medanos	Pittsburg	555	2001	Calpine	Combined cycle -Cogen
Delta Energy Facility	Pittsburg	887	2002	Calpine	Combined cycle
Gateway	Antioch	530	2009	PG&E	Combined cycle
March Landing	Antioch	760	2013	NRG	Combined cycle
Pittsburg	Pittsburg	1,029	1970s	NRG	Steam, combined cycle

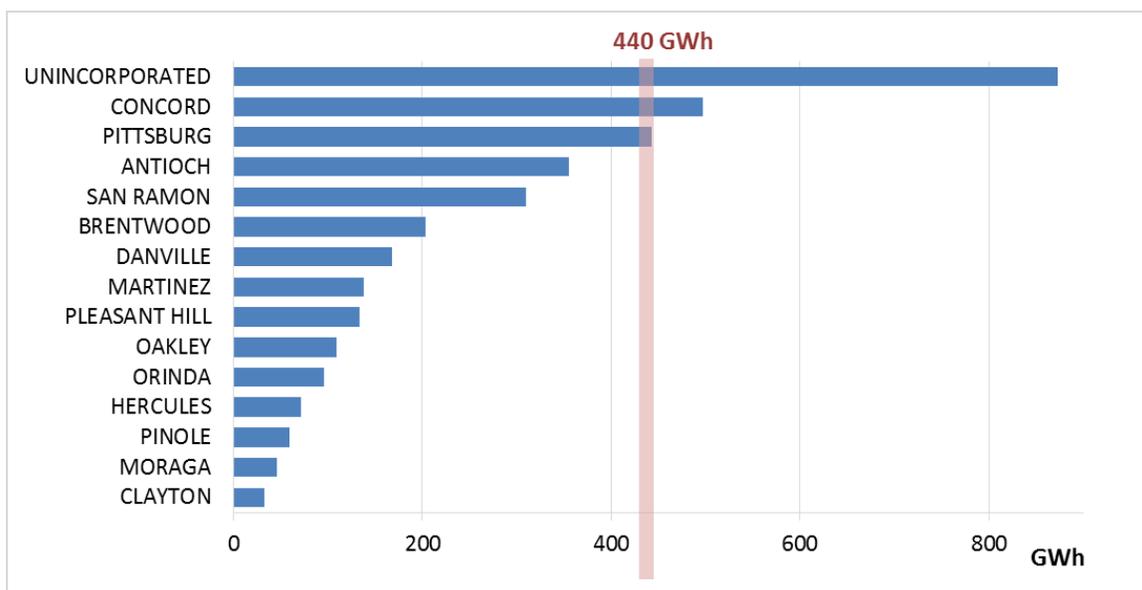
“Minimum” CCE Size?

MRW’s analysis above assumed that all eligible Contra Costa County cities join the Contra Costa County CCE program with a participation rate of 85% from each city, resulting in an anticipated CCE load of about 3.6 million MWh per year.⁶⁶ If fewer customers join, CCE rates will generally be higher because about \$7 million of annual CCE costs are invariant to the amount of CCE load. Along with the number of customers, the customer make-up is also important. For example, a higher share of residential customers would improve the competitiveness of the CCE, while a higher share of commercial customers or industrial customers would weaken the competitiveness of the CCE. Because cities vary in their distribution of customers by rate class, a city opting out of the CCE could affect the competitiveness of the CCE due to both the reduction in CCE load and the shift in customer make-up.

To identify the “minimum” load needed for CCE customer rates to be no higher than PG&E customer rates, we will analyze only the period between 2018 and 2030. The “minimum” load for this period is approximately 440,000 MWh per year, assuming the average customer portfolio for Contra Costa County and Supply Scenario 1. This value was estimated by assuming that the fixed costs remained the same (i.e., did not scale with sales) and then lowering the sales until the hypothetical reduced CCE’s rates were equal to PG&E’s. As shown in Figure 31, this is roughly the load from the big cities (Concord and Pittsburg) and is much smaller than the load from the unincorporated area. As long as two medium-sized cities or one larger city joins the CCE, this “minimum” load will be met. It is not a true minimum, however, because the true minimum depends on the make-up of the customer portfolio; for example, for the stand-alone city of Pittsburg,⁶⁷ due to its load with more industrial proportion, the CCE program would not be cost-competitive.

⁶⁶ In the alternate supply scenarios, the “minimum” annual load assuming the average customer portfolio for Contra Costa County and the base case is 550,000 MWh (Scenario 2).

⁶⁷ See Figure 2. Pittsburg is the only city with this highly industrial profile.

Figure 31. Potential load (85% participation) per city

Individuals and Communities Self-Selecting 100% Renewables

The existing CCEs all offer customers an option to choose to receive 100% of their power from renewable resources in exchange for a rate premium. However, each CCE's program is different. MCE Clean Energy has offered its "Deep Green" at a rate premium of 1¢/kWh because its inception. Sonoma Clean Power offers its "Evergreen" option at approximately the same price as PG&E's "Solar Choice" rate. Lancaster Choice Energy offers its Smart Choice as a fixed monthly premium rather than a variable rate. In all cases, only a very modest number of CCE customers—on the order of a few percent—have selected the 100% green rate option.

Table 32. CCE 100% Green Rate Premiums

CCE	Rate Option	Increment Above Default Rate
Marin Clean Energy	Deep Green	1¢/kWh
Sonoma Clean Power	EverGreen	3.5¢/kWh
Lancaster Choice Energy	Smart Choice	\$10/month
Peninsula Clean Energy	ECO100	1¢/kWh
CleanPowerSF	SuperGreen	2¢/kWh
Potential Contra Costa Co. CCE	TBD	~1.5¢/kWh

Any full renewable pricing option offered by the Contra Costa County CCE would have to be set by the CCE's management. The value shown in Table 32, ~1.5¢/kWh, is the average incremental cost of green power used in the CCE supply assessment (Scenario 2) over the study period. (Initially, it would have to be ~1.9¢/kWh.) The number of customers selecting the rate would not impact the economics of the CCE customer who remain on the standard rate.

- Separate CCE opt-out notifications would be needed. A key feature of the opt-out notification is the price comparisons against PG&E. As the default rate would be different for these communities, a different notice would have to be sent. This would simply increase the start-up cost for the CCE, the increment could be paid for by the city electing a different default rate.
- Having a higher default rate might increase the number of opt-outs in the community.
- PG&E's billing system would have to be able to handle city- or zip code-specific default options. That is, as new residential or businesses move to a self-selected green community, the billing system would need to know to default them on a different rate schedule than a customer in a different CCE community. This may or may not be an issue.

Competition with a PG&E Solar Choice Program

PG&E has been offering a solar choice program known as Green Tariff Shared Renewable Program since February 2015.⁶⁸ The program was established under Senate Bill 43, and pursuant to Decision 15-01-051 from the CPUC, to extend access to renewable energy to ratepayers that are currently unable to install onsite generation.⁶⁹ It offers homes and businesses the option to purchase 50% or 100% of their energy use from solar resources. The program provides those with homes or apartments or businesses that cannot support rooftop solar the opportunity to meet their electricity requirements through renewable energy and support the growth of renewable energy resources.

PG&E's current Solar Choice program costs residential customers an additional 3.58¢/kWh. Given that MRW projects that the CCE can offer 100% green power at ~1.5¢/kWh over its own Scenario 1 or Scenario 2 rate (which is projected to be less than PG&E's), we do not believe PG&E's Community Solar Program will be price competitive with similar CCE product options.

The program is open for enrollment until subscriptions reach 272 MW or January 1, 2019, whichever comes first.⁷⁰ While this does limit the ability for PG&E to provide a 100% renewable

⁶⁸ PG&E website

http://www.pge.com/en/b2b/energysupply/wholesaleelectricssuppliersolicitation/RFO/CommunitySolarChoice.page?WT.mc_id=Vanity_communitysolarchoice. Accessed 5/16/2016

⁶⁹ California Public Utilities Commission, Decision 15-01-051, p.3

⁷⁰ Solar Choice Program FAQs website,

<https://www.pge.com/en/myhome/saveenergymoney/solar/choice/faq/index.page> Accessed, 5/16/2016

option in the long-run, at the start of the CCE this program it provides an opportunity for customers who desire 100% renewable power to remain with PG&E.

Differences Between the Analyses for Contra Costa and Alameda Counties

In the first half of 2016, MRW prepared a similar CCE analysis for Alameda County.⁷¹ Although the fundamental approach and results of study and this one are the same, there are several differing assumptions resulting in differing results. If we compare the results of the present study with the results obtained in the Alameda CCE study, we observe that the savings for CCE customers are very similar in both studies, though PG&E rates and CCE rates are both approximately 1¢/kWh higher in the current study than in the prior study (**Table 33**).

Table 33. Average prices for 2018-2030 Scenario 1 for Contra Costa and Alameda County CCE programs

Average Period 2018-2030	Contra Costa County	Alameda County
Price natural gas (\$/MMBtu)	5.70	4.90
Wholesale (\$/MWh)	51.30	44.80
PG&E Capacity (\$/MWh)	74	39
CCE Capacity (\$/MWh)	52	39
Wind (\$/MWh)	56	57
Solar Distant (\$/MWh)	51	51
Solar Local (\$/MWh)	98	74
% Local Solar by 2030	25%	10%
PG&E rate (¢/kWh)	11.7	10.4
PCIA rate (¢/kWh)	1.4	1.4
CCE rate (¢/kWh)	9.4	8.3
Difference CCE-PGE (¢/kWh)	2.3	2.1

The results of the present study for Contra Costa County differ from the prior results for Alameda County because we updated our forecast to reflect new PG&E rate filings and other public forecasts. The main changes between the models are as follows:

- **Bundled Load Forecast:** As a result of increased interest in CCE, PG&E's most recent bundled load forecasts are 3% below the previously available forecasts for 2017 and an average of 25% below the previously available forecasts over the 2018-2030 period (see Figure 32).⁷² Less load reduces PG&E's procurement costs, increases the share of fixed costs

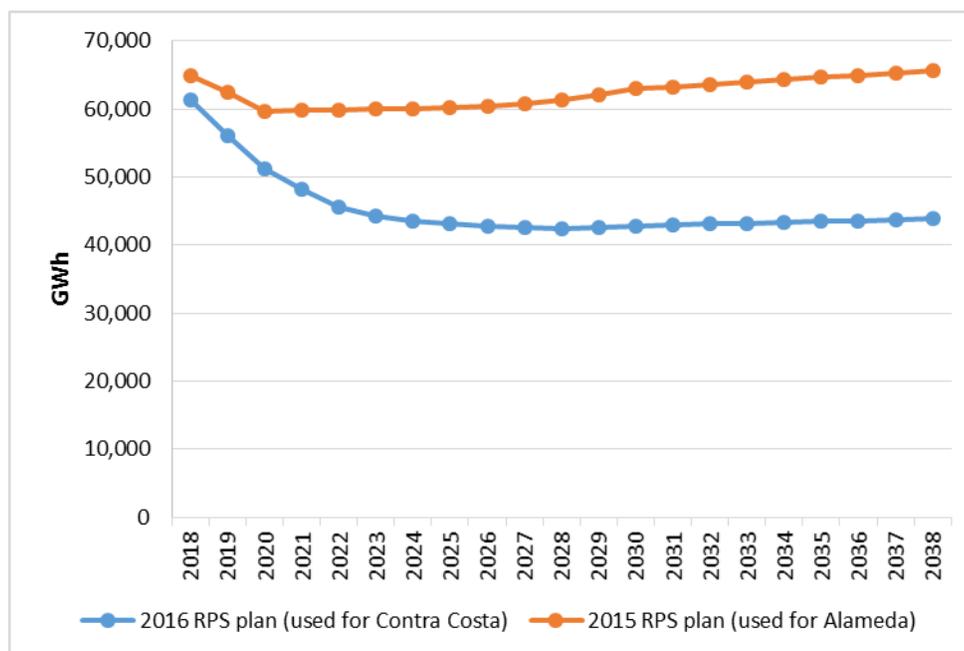
⁷¹ The final version of the Alameda CCE technical study was published on July 1, 2016.

<https://www.acgov.org/cda/planning/cca/documents/Feas-TechAnalysisDRAFT5312016.pdf>

⁷² The sources for the 2017 bundled load forecasts are PG&E's 2017 preliminary and final ERRAs forecasts. (The June 2016 preliminary forecast was used in the Alameda County CCE study, and the November 2016 final forecast

paid by remaining bundled customers, and increases the revenue provided to bundled customers from CCE exit fees. These effects mostly offset each other, resulting in little net change to bundled rates.⁷³

Figure 32: Bundled Load Forecasts used in the Alameda and Contra Costa County Analyses



- **Natural gas prices:** Projections for natural gas prices are about \$0.80/MMBtu higher than they were in the spring when the Alameda County report was developed. The higher natural gas prices increase wholesale market prices by \$7/MWh (14%).
- **Diablo Canyon Retirement application:** In July 2016, PG&E, together with other entities, submitted a proposal to retire the two units of Diablo Canyon when their licenses expire in November 2024 and August 2025. Per the proposal, PG&E would replace Diablo Canyon production with energy efficiency and greenhouse gas-free generation resources. These resources would include the following: (1) 2,000 GWh of load reduction from additional energy efficiency to be installed by January 2025, (2) 2,000 GWh of load reduction or generation from GHG-free generation resources to be on-line between 2025 and 2030, and (3) a voluntary commitment from PG&E to meet a 55% RPS for 2031-2045 (instead of the 50% requirement currently in effect). The joint proposal estimated that the retirement of Diablo Canyon would result in a need for new generation capacity (“load-resource balance”) around 2030, which is about five years earlier than previously anticipated.

was used in the present study.) The sources for the 2018-2030 bundled load forecasts are PG&E’s RPS plans for 2015 (filed in January 2016, used for Alameda County) and for 2016 (draft filed in August 2016, used for Contra Costa).

⁷³ CCE exit fees are designed so that bundled customers’ rates are not affected by CCE departures. In practice, some impact is likely in one direction or the other, and the magnitude and direction of this impact may each vary year by year.

The new energy efficiency resources together with other costs of the nuclear plant retirement would be recovered through non-generation rates (mostly Public Purpose Program and Nuclear Decommissioning charges), and the new RPS resources would be recovered through a new “Clean Energy Charge” applied to all PG&E retail customers. For those load serving entities that are willing to commit to procuring the equivalent new RPS resources, PG&E has proposed a “self-provision” option that would exempt existing DA and CCE loads from the Clean Energy Charge. In the analysis for Contra Costa County, MRW assumed that Contra Costa CCE would choose the “self-provision” option.

MRW assumed for this study that the Diablo Canyon retirement proposal would be adopted, though the proposal is under evaluation by the Commission and is subject to modification. Based on this proposal, we modified the PG&E and Contra Costa County CCE power supply forecasts as follows:⁷⁴

- 1) PG&E’s RPS requirements were increased for 2030-2038 from 50% to 55%,⁷⁵
- 2) Contra Costa County CCE’s RPS requirements were increased for 2030-2038 to 55% (vs. the 50% that was used in the Alameda County CCE study), and
- 3) We began increasing the price of capacity five years earlier than we had in the Alameda County CCE study, reflecting the earlier load-resource balance date due to the retirement of Diablo Canyon. For both Alameda and Contra Costa counties, MRW assumed that the CCEs would build their own power plants (alone or in combination with other public entities) in place of purchasing market capacity when market prices rise above the cost of a new self-build.

On February 27, 2017, PG&E withdrew portions of its Diablo Canyon retirement proposal. In particular, PG&E states it will still pursue GHG-free replacement resources, but will do so in a different CPUC proceeding. MRW does not believe that this change has a material impact on this analysis.

⁷⁴ We also accounted for the changes in the Public Purpose Program and Nuclear Decommissioning fees in our calculation of the Residential bills.

⁷⁵ The generation share of the 2025-2030 commitment for 2,000 GWh of load reduction or GHG-free generation was assumed to be subsumed by procurement needed to meet a 50% RPS by 2030 and therefore did not result in incremental renewable generation in our model.

Chapter 9: Conclusions

Overall, a CCE in Contra Costa County appears feasible. Given current and expected market and regulatory conditions, a Contra Costa County CCE should be able to offer its residents and business electric rates that are less than that available from PG&E.

Sensitivity analyses suggest that these results are relatively robust. Only when very high amounts of local renewable energy are assumed in the CCE portfolio (Scenario 4), combined with other negative factors, do PG&E's rates become consistently more favorable than the CCE's.

A Contra Costa County CCE would also be well positioned to help facilitate the installation of greater amounts renewable generation in the County. Because the CCE would have a much greater interest in developing local solar than PG&E, it is much more likely that such development would actually occur with a CCE in the County than without it.

The CCE can also reduce the amount greenhouse gases emitted by the County, but only under certain circumstances. Because PG&E's supply portfolio has significant carbon-free generation (large hydroelectric and nuclear generators), the CCE must contract for significant amounts of carbon-free power above and beyond the required qualifying renewables in order to actually reduce the County's electric carbon footprint. Therefore, if carbon reductions are a high priority for the CCE, a concerted effort to contract with hydroelectric or other carbon-free generators would be needed.

A CCE can also offer positive economic development and employment benefits to the County. At the peak, the CCE could create approximately 500 to 700 new jobs in the County, plus an additional 200 jobs in the neighboring counties if local renewable development is prioritized.

While the analytical focus of this report has been on a stand-alone Contra Costa County CCE for those communities not already in MCE that is not the only, nor necessarily best, choice for these communities. Overall, there is insufficient data to suggest that a stand-alone Contra Costa CCE would offer lower rates or greater GHG savings that joining MCE or EBCE. Either forming or joining a CCE would likely offer modestly lower rates and more local economic development that remaining with PG&E. Joining MCE would likely result in the quickest and least risky path to CCE implementation, however with diminished local input into CCE policy formation. Because it has yet to be formed, joining with EBCE would take longer and involve more uncertainty than joining the already-established MCE, but would offer greater input into the CCE's policies and formation.

Although this study suggests CCE program options would likely produce both environmental and economic benefits for the jurisdictions included in the study, continuing service with PG&E remains an option for not only a community but also for any individual or business whose community has selected CCE service. PG&E is an experienced power provider and is regulated by the state. Furthermore, remaining with PG&E takes no city action. Lastly, simply because a Contra Costa community does not join a CCE in 2017 or 2018 does not necessarily preclude it from doing so in the future, although waiting may result in an "entry fee" or perhaps a high PCIA rate.